NSTAR
ELECTRIC
GAS

Legal Department, 17th Floor
800 Boylston Street, Boston, Massachusetts 02199

JOHN COPE-FLANAGAN
Assistant General Counsel

Cambridge Electric Light Company
Direct Dial:(617) 424-2103
Telecopier:(617) 424-2733
John_Cope-Flanagan@Nstaronline.com

March 5, 2002

Mary L. Cottrell, Secretary
Department of Telecommunications & Energy
One South Station, 2nd Floor
Boston, Massachusetts 02110

Re: Cambridge Electric Light Company
D.T.E. 01-94

Dear Madam Secretary:

Cambridge Electric Light Company (the "Company") is pleased to supply its responses to the record requests listed on the attached sheet.

Sincerely,

John Cope-Flanagan

John Cope-Flanagan

Enclosures

cc: Jesse S. Reyes, Hearing Officer (2 copies)
Esat Serhat Guney, Analyst, Rates and Revenue Requirements Division
Joseph Tiernan, Analyst, Rates and Revenue Requirements Division
Miguel Maravi, Analyst, Rates and Revenue Requirements Division
Alexander Cochis, Esq., Assistant Attorney General
Carrol R. Wasserman, Esq.
David Rosenzweig, Esq.
Stephen Klionsky, Esq.

Responses to Record Requests

RR-AG-1
RR-AG-2
RR-AG-7
RR-AG-10

March 5, 2002

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Cambridge Electric Light Company	)	D.T.E. 01-94

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing responses to information requests in accordance with Department rules.

John Cope-Flanagan

John Cope-Flanagan
Attorney for
NSTAR Electric & Gas Corporation
800 Boylston St., Floor 17
Boston, MA 02199

DATED: March 5, 2002

Record Request AG-1

Provide a copy of any approval by the Federal Energy Regulatory Commission, and any related correspondence, regarding the sales transaction between Vermont Yankee and Entergy and any other related transaction.

Response

Please see Attachment RR-AG-1 for a copy of the Order of the Federal Energy Regulatory Commission authorizing the sales transaction between Vermont Yankee and Entergy.

UNITED STATES OF AMERICA 98 FERC & 61,122
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
William L. Massey, Linda Breathitt,
and Nora Mead Brownell.

Vermont Yankee Nuclear Power Corporation Entergy Nuclear Vermont Yankee, LLC	Docket Nos. EC02-5-000, ER02-211-000
Vermont Yankee Nuclear Power Corporation	EL02-53-000

ORDER AUTHORIZING DISPOSITION OF JURISDICTIONAL FACILITIES,
ACCEPTING FOR FILING CERTAIN MODIFYING AGREEMENTS,
AND ESTABLISHING HEARING AND SETTLEMENT JUDGE PROCEDURES

(Issued February 1, 2002)

On October 12, 2001, under Section 203 of the Federal Power Act (FPA),[1] Vermont Yankee Nuclear Power Corporation (Vermont Yankee) and Entergy Nuclear Vermont Yankee, LLC (Entergy VY) (collectively, Applicants) sought Commission authorization, in Docket No. EC02-5-000, for the sale by Vermont Yankee to Entergy VY of certain jurisdictional facilities associated with the Vermont Yankee Nuclear Power Station (Plant); i.e., the generator leads, step-up transformer and associated switch yard facilities (Interconnection Facilities). The Interconnection Facilities are all in the New England Power Pool (NEPOOL), and the control area functions are under the administration of the New England Independent System Operator (NE ISO). Applicants explain that the purchasers of the Plant's output will obtain transmission services directly from the NE ISO.

On October 31, 2001, pursuant to Section 205 of the FPA, Vermont Yankee filed six agreements (Amendatory Agreements), in Docket No. ER02-211-000, to modify the wholesale power contracts (Power Contracts and Additional Power Contracts, collectively "Contracts") with the public utilities (Purchasers) that purchase the entire output of the Plant. The Amendatory Agreements are intended to reflect the sale of the Plant to Entergy VY. There are related Purchase Power Agreements (PPAs) under which Entergy VY will sell the Plant's entire output back to Vermont Yankee at fixed rates under Entergy VY's market-based power sales

[1] 16 U.S.C. ' 824b (1994).

tariff.[1] Vermont Yankee will pass on to its Purchasers the purchased power costs from Entergy VY under the PPA, Vermont Yankee's administrative costs, any unrecovered investment costs, and any costs associated with any residual obligations under the Contracts. Vermont Yankee projects that the Amendatory Agreements will reduce its wholesale charges under the Contracts. It requests that the Amendatory Agreements become effective upon closing the sale of the Plant.

As discussed below, the Commission concludes that the proposed disposition of jurisdictional facilities will not adversely affect competition, rates, or regulation. It is therefore approved, without condition, as consistent with the public interest. In addition, we will accept the proposed Amendatory Agreements and set for hearing Vermont Yankee's rates other than purchase power costs. This order serves the public interest by ensuring that the disposition and related rate filings meet the public interest and just and reasonable standards in the FPA.

I. BACKGROUND

A. Description of the Parties and the Plant

Vermont Yankee owns and operates a single nuclear generating plant located in Vernon, Vermont.[2] The Plant has a nominal capacity of 506 MW.[3] Vermont Yankee sells the entire output of the Plant to eight sponsoring utilities (Sponsors or Purchasers), and a portion of the output is resold to certain municipals and cooperatives (Secondary Purchasers). Vermont Yankee's Board of Directors has approved a Purchase and Sale Agreement (PSA) for the sale of the Plant and related assets, including a decommissioning trust pre-funded to an agreed level, to Entergy VY.

Entergy VY is a wholly-owned direct subsidiary of Entergy Nuclear Vermont Investment Company, which, in turn, is an indirect subsidiary of Entergy Nuclear Holding Company. Entergy Nuclear Holding Company is a wholly-owned direct subsidiary of Entergy, a Delaware corporation and a registered public utility holding company under the Public Utility Holding Company Act (PUHCA). The Plant will be operated by Entergy Nuclear Operations, Inc., an indirect subsidiary of Entergy, as agent for Entergy VY.

B. The Proposed Transaction and Related Filings

Under the Amendatory Agreements, the Contracts will become the vehicles through which Vermont Yankee resells electricity from the Plant to the Purchasers and is compensated for the costs it incurs in doing so. Vermont Yankee agreed to sell the Plant and associated transmission assets to Entergy VY for $180 million and simultaneously buy back the output through March 21, 2012, the end of the Plant's current operating license. The PPAs adopt a payment structure that differs from the existing cost-of-service formula under the Contracts. The PPAs collect all the Plant's operation, maintenance and decommissioning costs on a "unit contingent basis" under which Vermont Yankee will pay a monthly fixed price per megawatt hour for electricity actually delivered up to the

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[1]The PPAs are being considered by the Commission in Docket No. ER02-564-000.

[2]The Plant commenced commercial operations on November 30, 1972, and is currently licensed by the Nuclear Regulatory Commission (NRC) to operate until March 21, 2012.

[3]According to the testimony of Bruce Wiggett at 3, the Plant's most recent winter and summer ratings by NE ISO were 529 and 506 megawatts, respectively.

Maximum Monthly Amount (MMA) as set forth in Schedule B of the PPAs.[4] Because of this "unit contingent basis," Entergy VY will bear all risks that the costs of operating the Plant will increase or that its output will decline. For monthly amounts of energy in excess of the MMA, Vermont Yankee will pay the monthly NEPOOL clearing price.

Vermont Yankee will use the sale proceeds, net of $5 million cash working capital and other sale expenses, to pay off debt and buy back or return capital related to some of Vermont Yankee's common stock.[5] After the sale, Entergy VY will assume all responsibility for operating the plant, including the obligation to decommission the plant, and Vermont Yankee will transfer to Entergy VY the external decommissioning fund. If the value of the fund at closing meets or exceeds the NRC's minimum required funding amount for decommissioning, Vermont Yankee will not be required to top off the fund.[6] If this is not the case, Vermont Yankee will have to make a top off payment to meet the minimum funding amount; that payment is capped at $5.4 million.

In addition, beginning approximately October 2005 (after refueling outage No. 25 is completed), a Low Market Adjuster (LMA)[7] will become effective. Should the market price of energy in NEPOOL significantly decline, the LMA will adjust the fixed prices of energy ($/MWh) in the PPAs to more closely reflect the market value of energy. Specifically, if NEPOOL's average hourly spot clearing price in the prior year (Market Price) goes below 95 percent of the fixed monthly rates in the PPAs, then Vermont Yankee will pay that Market Price multiplied by 105 percent.[8] After 2005, this ensures that Purchasers will not pay rates substantially greater than market values.

II. NOTICE, COMMENTS, PROTESTS AND ANSWERS

Notices of Applicants' filings were published in the Federal Register, 66 Fed. Reg. 53,601 (October 23, 2001) and 66 Fed. Reg. 56,817 (November 13, 2001), with comments, protests, and interventions due on or before November 2, 2001, and December 11, 2001.[9]

On November 19, 2001, the Secondary Purchasers filed a motion to intervene in Docket Nos. EC02-5-000 and ER02-211-000. Secondary Purchasers advise that they have reached a settlement agreement in principle with the Purchasers whereby they would forgo raising any issues with respect to the plant sale in exchange for an early

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[4]The MMA is based on unit capacity output of 510 MW net and is reduced by that capacity amount times the actual number of hours that the Plant produces no energy.

[5]Testimony of Bruce W. Wiggett at 12-13.

[6]Id.

[7]This adjuster reflects the value of installed capacity by either including the "actual clearing price for Installed Capability" or, if there is no clearing price, providing for a 10 percent adder. See Testimony of Bruce Wiggett at 16.

[8]See PPAs, Article 5, Purchase Price for Facility Product.

[9]On December 12, 2001, in Docket No. ER02-528-000, termination notices were filed for the Secondary Purchasers in Vermont. On December 7, 2001, in Docket No. ER02-505-000, as amended on December 11 and 20, 2001, notices of cancellation were filed for all other Secondary Purchasers.

termination of their contracts. Secondary Purchasers expressly reserve their right to supplement their intervention and raise specific issues with regard to the proposed Plant sale transaction if the settlement is not finalized and notices of termination are not filed in a timely fashion.

On November 21, 2001, the Vermont Department of Public Service (Vermont DPS) filed in Docket Nos. EC02-5-000 and ER02-211-000 a protest, request for settlement procedures, motion to intervene and motion to consolidate proceedings. Vermont DPS protests the rates Vermont Yankee will charge the Purchasers, including Vermont Yankee's 11 percent rate of return on equity (ROE). Vermont DPS notes that the filings are a complete restructuring of the way that power from the plant is resold. It contends that Vermont Yankee's claimed 2001 operation expenses and $250 million of projected savings are overstated because a number of items are incorrect or have been left out of that analysis.[10] It also complains that, historically, Purchasers received energy that exceeded the monthly MMA limits at little or no incremental cost; however, if the transaction is approved, that benefit to Vermont ratepayers would be lost. Vermont DPS also advises that many nuclear units are increasing their power levels through a mechanism called power "uprate,"[11] and complains that Article 8 of the PPAs denies Vermont ratepayers any benefit from an uprate. It concludes that the base price projections, i.e., the rates to be charged by Entergy VY for sales to Vermont Yankee, have not been shown to be just and reasonable.

Vermont DPS also notes that Docket Nos. EC01-5-000 and ER02-211-000 are parts of the same transaction and requests that the two dockets be consolidated. It claims that consolidation would be consistent with the Commission's treatment of the prior proposed sale of the Plant.[12] Vermont DPS notes that the parties have a history of resolving matters related to the Plant without resorting to an evidentiary proceeding. It also advises that Vermont Yankee and Entergy VY have filed with the Vermont Public Service Board (VPSB) a request to approve the transaction, i.e., the sale of the plant. Since many of the issues that it raises here are before the VPSB, Vermont DPS requests that settlement procedures be established that coordinate the federal and state proceedings.

On December 6, 2001, Applicants submitted an answer to Vermont DPS's filing in Docket No. ER02-211-000. Applicants acknowledge that the fixed rates in the PPAs were negotiated. However, they contend that Vermont DPS fails to identify any element in the Amendatory Agreements requiring investigation. Applicants claim that Vermont DPS does not dispute whether net savings will occur during 2002 and over the ten-year term of the Amendatory Agreements, but only the precise amount of savings. With respect to the current authorized 11 percent ROE, Applicants contend that the protest is procedurally flawed because Applicants do not propose to change the ROE. Noting that the equity structure will only consist of about $5 million in working capital,

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[10] Specifically, Vermont DPS complains that the pricing of power in 2002 is skewed (fixed rates in $/MWh's for 2002 are: $30 from March through June; $55 for July and August; and $49 for September through December). It also states that the unit's scheduling is flawed because savings primarily occur in months when the Plant's scheduled output is low. Vermont DPS also claims that Vermont Yankee's budgeted operating costs for 2001 are overstated by as much as $20 million suggesting additional operational savings for continued ownership of the Plant in 2002 and beyond.

[11] Under Article 8(a) of the PPAs, Seller may make capital improvements or related adjustments to operating parameters, set points, instruments and procedures to increase the Installed Capability, or Energy output of the Facility (an "Uprate").

[12] Citing Vermont Yankee Nuclear Power Corp., et al., 91 FERC & 61,325 (2000).

Applicants contend that the effect after sale of the plant would only be $85,000 for a 1 percent change in the equity rate as compared to annual revenues of $152 million to $187 million. With respect to whether Entergy VY should have market-based rate authority, Applicants argue that Vermont DPS can raise any concerns it wants in the docket that the Commission established to consider the application for wholesale market-based rate authority.[13]

On December 21, 2001, Applicants submitted an answer to Vermont DPS's filing in Docket No. EC02-5-000. Applicants contend that Vermont DPS fails to demonstrate that the sale of the Vermont Yankee plant is inconsistent with the public interest. Applicants note that Vermont DPS does not contest the three-part test the Commission set forth to evaluate asset divestiture applications; Vermont DPS instead argues that Vermont Yankee's expected savings from the plant are uncertain and undocumented. Applicants contend that such an issue should be addressed in the state proceeding and not in this Commission's proceedings. They state that the magnitude of savings is not a factor this Commission considers under Section 203.

Both of Applicants' answers oppose consolidation, arguing that such action would only lead to confusion regarding the status of the approval granted under Section 203, unnecessarily delaying the transaction.

III. DISCUSSION

A. Procedural Matters

Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure,[14] the timely, unopposed motions to intervene of Secondary Purchasers and the Vermont DPS serve to make them parties to this proceeding.

Rule 213 of the Commission's Rules of Practice and Procedure[15] prohibits answers unless otherwise permitted by the decisional authority. We find that good cause exists to allow Vermont Yankee and Entergy VY's answers because they assist us in the decision-making process.

B. The Transaction - Section 203 Issues

1. Standard of Review

Section 203(a) of the FPA provides that the Commission must approve a proposed disposition if it finds that the disposition "will be consistent with the public interest."[16] The Commission generally takes account of three factors in analyzing proposed dispositions of facilities: (a) the effect on competition; (b) the effect on rates; and 8) the effect on regulation.[17]

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[13]Citing AEP Power Marketing, Inc., et al., 97 FERC & 61,219 (2001).

[14]18 C.F.R. ' 385.214 (2001).

[15]18 C.F.R. ' 385.213(a)(2) (2001).

[16]16 U.S.C. ' 824b(a) (1994).

[17]See Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement, Order No. 592, 61 Fed. Reg. 68,595 (December 30, 1996), FERC Statutes and Regulations, Regulations Preambles July 1996-December 2000 & 31,044 (1996), order on reh'g, Order No. 592-

2. Effect on Competition

Applicants submitted an Appendix A analysis that examines the effect of the Transaction on relevant wholesale energy and capacity markets. They conclude that the transfer of the Plant from Vermont Yankee to Entergy VY will not adversely affect competition in these markets.

a. Relevant Products

Applicants define short-to-intermediate capacity and ancillary services as the relevant products.[18] Applicants use economic capacity[19] as a proxy for short-to-intermediate term capacity. They argue that given the rapid movement toward full-scale retail access in the Northeast, economic capacity is a better measure than available economic capacity.

b. Relevant Markets

In their Appendix A analysis, Applicants define NEPOOL, the New York Independent System Operator (NYISO) and that part of the NYISO that lies east of the Total East transmission constraint as the relevant geographic markets. Applicants acknowledge that the NEPOOL market is at times internally constrained, leading to smaller relevant geographic markets in New England. However, Vermont Yankee and Entergy VY's other generation located within New England (Pilgrim nuclear plant) are located in different sub-regions within New England. Applicants conclude that examining NEPOOL as a single market is more conservative (less favorable to

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A, 62 Fed. Reg. 33,341 (June 19, 1997), 79 FERC & 61,321 (1997) (Merger Policy Statement); see also Revised Filing Requirements Under Part 33 of the Commission's Regulations, Order No. 642, 65 Fed. Reg. 70,983 (November 28, 2000), FERC Statutes and Regulations, Regulations Preambles July 1996-December 2000 & 31,111 (2000), order on reh'g, Order No. 642-A, 66 Fed. Reg. 16,121 (March 23, 2001), 94 FERC & 61,289 (2001).

[18] Applicants state that Installed Capacity (ICAP) is the only ancillary service market that could be affected by the proposed transaction. Application Exhibit 1 at 12.

[19] The starting point for calculating economic capacity is the supplier's own generation capacity with low enough variable costs that energy can be delivered to a market (after paying all necessary transmission and ancillary service costs, including losses) at a price that is five percent or less above the pre-merger market price. Capacity must be decreased to reflect any portion committed to long-term firm sales; and it must be increased to reflect any portion acquired by long-term firm purchases. In addition, any capacity under the operational control of a party other than the owner must be attributed to the party for whose economic benefit the related unit is operated. The result of these calculations is the supplier's "economic capacity." See Revised Filing Requirements Under Part 33 of the Commission's Regulations, Order No. 642, 65 Fed. Reg. 70,983 (2000), FERC Stats. & Regs. & 31,111 (2000), order on reh'g, Order No. 642-A, 94 FERC & 61,289 (2001).

Applicants) than examining all of the sub-regions. In their analysis of ancillary service markets, Applicants define NEPOOL as the relevant geographic market, since neither of Entergy Nuclear's generation facilities can provide ancillary services outside of New England.

c. Appendix A Analysis

Applicants analyze the effect of the proposed transfer on economic capacity in the relevant geographic markets using the Delivered Price Test. They evaluate conditions assuming market prices ranging from $20 per MWh to $150 per MWh. The prices are based on a review of 1999 system lambdas and 1999-2000 market prices. They define 11 time periods.[20] Applicants claim that the range of prices combined with the time periods reflects a sufficient range of system conditions such that the analysis captures the full effect of the proposed transfer on competition in the relevant markets.[21]

Applicants report no screen failures in the analysis of economic capacity. They also report no screen failures in their analysis of the NEPOOL ICAP market. Applicants state there are no vertical concerns raised by the transaction since neither Entergy Nuclear nor Vermont Yankee nor any of their affiliates owns any electric transmission facilities in the region. Applicants conclude that the proposed transaction will not harm competition.

d. Commission Conclusion

Applicants have shown that the proposed transfer does not adversely affect competition in the relevant markets. We agree with Applicants that the analysis reflects a sufficient range of system conditions to capture the full effect of the proposed transfer on competition in the those markets. We also agree with Applicants' conclusion that since Entergy Nuclear's generation facilities are located in different sub-regions of New England, their analysis of NEPOOL is conservative. We find no vertical concerns with the transaction, since neither Entergy Nuclear nor Vermont Yankee nor any of its affiliates own or control transmission facilities or fuel input supplies in the region. Finally we note that no commenter argues that there will be harm to competition.

3. Effect on Rates

a. Applicants' Analysis

Applicants state that the proposed transaction would not have an adverse effect on rates. They claim that the arrangements associated with the sale of the Plant to Entergy Nuclear VY would reduce both wholesale rates and the risks borne by Vermont Yankee's wholesale customers. Moreover, Applicants claim that the Purchasers would be protected from any adverse rate consequences because the Amendatory Agreements: (1) replace the principal part of the Power Contract's formula mechanism for the recovery of costs of operating and maintaining the Plant to produce electricity with fixed rate provisions under the PPAs; and (2) remove the obligation of the Purchasers to pay all costs associated with decommissioning the Plant and replace it with the agreed level of funding for decommissioning as indicated in the PSA.[22] This would reduce the risk that rates to Vermont Yankee's wholesale

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[20] The time periods are Summer Off-Peak, Summer-Peak, Summer Super-Peak 1, Summer Super-Peak 2, Summer-Peak 3, Winter Off-Peak, Winter Peak, Winter Super Peak, Shoulder Off-Peak, Shoulder Peak and Shoulder Super-Peak.

[21] Application Schedule 1 at 10.

[22] Mr. Wiggett projects that the proceeds of the sale of the Plant will be sufficient to cover all of the Purchasers' obligations under the PSA to compensate Vermont Yankee for its investment in the Plant and transfer funding for decommissioning to Entergy VY.

customers will increase if the costs of operating and/or decommissioning the Plant increase. Moreover, Applicants contend that the proposed Amendatory Agreements are a partial rate freeze, further protecting wholesale customers.

Applicants also argue that the sale of the Plant would not have an adverse effect on wholesale rates to any Secondary Purchasers. They contend that the Secondary Purchasers would be protected because the Purchasers have committed to cap their recovery of costs under long-term power contracts with the Secondary Purchasers.[23] The Purchasers would cap the total amount charged to the Secondary Purchasers at the average of the amount charged during the last five full calender years escalated to current year dollars, assuming an inflation rate of three percent per year. Accordingly, Applicants contend that the proposed transaction would not increase the Secondary Purchasers' rates because they would not pay more for the Vermont Yankee power after the sale than the average amount they paid before the sale.

b. Intervenors' Concerns

The Secondary Purchasers argue that the proposed sale of the Plant to Entergy Nuclear VY and the related Amendatory Agreements would restructure the Contracts under which the Purchasers have purchased the output of the Plant at cost-of-service formula rates. However, the Secondary Purchasers, Applicants, and the Purchasers have reached a settlement in principle concerning rates. Therefore, the Secondary Purchasers will forgo raising any issues in exchange for early termination of their Vermont Yankee contracts.

Vermont DPS protests the filing, arguing, among other things, that the application fails to demonstrate that the proposed transfer is consistent with the public interest. Although Applicants estimate a savings of approximately $30 million in the first year after the disposition and approximately $250 million over the term of the Amendatory Agreements, Vermont DPS contends that the savings are overstated. Vermont DPS argues that under current pricing, Purchasers obtain generated energy that exceeds the PPAs' limits at little or no incremental costs, where under the PPAs this benefit would be lost.

c. Commission Determination

We find that adequate ratepayer protection has been proposed by Applicants. The replacement of the open-ended formula rate with a stated rate provision and the reduced risks with respect to decommissioning expenses are specifically designed to protect Vermont ratepayers. Further, the LMA provides added protection to the Purchasers; if the market value of energy in NEPOOL declines the stated rates under the PPAs will be reduced to the annual market price plus 5 percent. Moreover, protection is also in place in the event of a catastrophic Plant failure or permanent retirement of the facility. The Purchasers do not have to pay unless the Plant produces energy. Finally, the Purchasers have two open seasons in which they could exercise their option to terminate all or part of their obligations under the PPAs.[24]

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[23]Applicants explain that most of these contracts expire at the end of November 2002. Under the contracts, each Purchaser is entitled to a portion of the power and energy produced by the Plant at the same percentage of costs as was incurred by the Purchaser.

[24]See Amendatory Agreements, PPAs, Article 4, Term, Regulatory Approvals, Early Termination (stating that Purchasers can give a 180 days notice prior to February 28, 2005, and December 31, 2007 to terminate their obligations).

The rate concerns raised by Vermont DPS, such as the overstatement of savings and limits on monthly delivered energy, are beyond the scope of the Commission's review of this transaction under section 203.[25] The Commission's primary focus under Section 203, with regard to the effect on rates factor, is to ensure that customers are protected from adverse rate effects. With regard to the effect on rates for Section 203 purposes, the Commission no longer requires applicants and intervenors to estimate the future costs and benefits of a merger and demonstrate that the benefits will exceed the costs. Instead, we require applicants to propose appropriate rate protection for customers.[26] We find that the protections incorporated in the Amendatory Agreements above satisfy our requirements for rate protection under Section 203 of the FPA. The justness and reasonableness of the proposed rates are discussed separately in this order under Section 205 issues.

4. Effect on Regulation

As explained in the Merger Policy Statement, the Commission's primary concern with the effect on regulation of a proposed disposition of a jurisdictional facility involves possible changes in the Commission's jurisdiction when a registered holding company is formed, thus invoking the jurisdiction of the Securities and Exchange Commission. We are also concerned with the effect on state regulation where a state does not have authority to act on a merger and has raised concerns about the effect on its regulation of the merged entity.[27]

The Transaction will not adversely affect the Commission's jurisdiction because: (1) the Transaction will not result in the formation of a registered holding company; (2) all wholesale sales made by Vermont Yankee to Purchasers, by Purchasers to the Secondary Purchasers, and by Entergy VY will continue to be subject to the Commission's review; and (3) Entergy, as a registered public utility holding company under PUHCA, commits to abide by the Commission's policy regarding the treatment of costs and revenues related to intra-company transactions.

The proposed sale will be subject to the approval of the VPSB. Applicants also state that they will make appropriate applications to other state Commissions as necessary. Therefore, the proposed sale does not raise concerns over the effect on state regulation.

For these reasons, and because no intervenor argues to the contrary, we conclude that the proposed transaction will not adversely affect regulation.

5. Accounting Issues

The sale of the Plant and Interconnection Facilities to Entergy VY is the sale of an operating unit or system that must be accounted for in accordance with the provisions of Electric Plant Instruction No. 5 and the instructions to Account 102 of the Uniform System of Accounts.[28] Vermont Yankee shall file its accounting for the sale with the Commission, including complete narrative explanations, within six months of the date of the Transaction.

C. The Transaction B Section 205 Issues

1. The Amendatory Agreements

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[25] See Niagara Mohawk, 87 FERC & 61,283 at 62,138 (1999).

[26] Merger Policy Statement at 30,123.

[27] Id. at 30,124-125.

[28] Electric Plant Instruction No. 5, Electric Plant Purchased or Sold, and Account 102, Electric Plant Purchased or Sold, 18 C.F.R. Part 101 (2001).

The Amendatory Agreements fundamentally restructure the existing Contracts among Vermont Yankee and the Purchasers. Based on projections, Vermont Yankee claims that charges under the Amendatory Agreements will be approximately $30 million lower in the first year after the sale and $250 million lower on a discounted basis over ten years. Vermont DPS disputes Vermont Yankee's projected savings, claiming that they are based on improper assumptions. Vermont DPS alleges that no actual savings will accrue in 2002. It also protests the rates in the Amendatory Agreements, including Vermont Yankee's 11 percent ROE. Vermont DPS concludes that charges under the Amendatory Agreements have not been shown to be just and reasonable. In their answer, Applicants claim that Vermont DPS failed to identify any item in the Amendatory Agreements requiring investigation. Applicants contend that the ROE amounts are too small to affect the justness and reasonableness of Vermont Yankee's wholesale rates.

We note that neither the PPAs (which were negotiated between the Applicants) nor the requested authorization for market-based rates have been accepted by the Commission in Docket No. ER02-564-000. Vermont DPS alleges that the base price projections were not shown to be just and reasonable; however, it acknowledges that there are both benefits and burdens for ratepayers in the PPAs. Applicants argue that Vermont DPS's concerns are outside the scope of this proceeding, and can instead be raised in the Docket No. ER02-564-000 proceeding, which the Commission established to consider the application for wholesale market rate authority.[29] The determination of whether the proposed market-based rates under the PPAs are just and reasonable will be in Docket No. ER02-564-000. Under these circumstances, we will accept the PPAs in Docket No. ER02-211-000 for filing, subject to the outcome of Docket No. ER02-564-000.

In addition to the PPAs' stated energy rates, Purchasers will continue to pay their entitlement percentage of Vermont Yankee's ongoing administrative costs, any unrecovered investment costs (after crediting the Plant's net sale proceeds), and any continuing obligations under the Contracts. Vermont DPS raises concerns that the current 11 percent ROE on Vermont Yankee's remaining rate base does not reflect the actual future risks. Applicants contend that Vermont DPS's ROE complaint is procedurally defective[30] and is of no moment because the equity return is insignificant as compared to total annual revenue after sale of the Plant. Based on our preliminary analysis, we find that the existing ROE may be excessive by more than 1 percent (as suggested by Applicants) and could remain in effect for ten years. Under these circumstances, we will suspend the Amendatory Agreements for a nominal period and allow them to go into effect on the date that service commences, subject to refund and establish hearing and settlement procedures.

In order to provide the parties an opportunity to resolve these matters among themselves, we will hold the hearing in abeyance and direct settlement judge procedures, pursuant to Rule 603 of the Commission's Rules of Practice and Procedure.[31] If the parties desire, they may, by mutual agreement, request a specific judge as the settlement judge in this proceeding; otherwise, the Chief Judge will select a judge for this purpose.[32] The settlement

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[29] Citing AEP Power Marketing, Inc., et al., 97 FERC & 61,219 (2001).

[30] Applicants argue that the Commission has found that challenges in a protest to an amendment of other provisions of a rate schedule are inappropriate. Citing Consolidated Edison Co. of New York, 97 FERC & 61,241 (2001); Louisiana Power & Light Co., 50 FERC & 61,040 (1990). We agree with Applicants and find that the proper method for challenging Vermont Yankee's formula rates is through a petition for investigation under Section 206 of the FPA.

[31] 18 C.F.R. ' 35.2(b) & n.1 (2001).

[32] If the parties decide to request a specific judge, they must make their joint request to the Chief Judge by telephone at (202) 219-2500 within 5 days of this

judge shall report to the Chief Judge and the Commission within 60 days of the date of this order concerning the status of settlement discussions. Based on this report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions or provide for commencement of a hearing by assigning the case to a presiding judge.

Since we find that a further reduction in rates may be warranted in Docket No. ER02-211-000, on our own motion, we will institute an investigation under section 206 of the FPA and establish a refund effective date. When the Commission institutes an investigation on its own motion, Section 206(b) requires that the Commission establish a refund effective date that is no earlier than 60 days after publication of notice of the Commission's investigation in the Federal Register, and no later than five months subsequent to the expiration of the 60 day period. In order to give maximum protection to consumers, we will establish a refund effective date of 60 days from the date on which notice of the investigation in Docket No. EL02-53-000 is published in the Federal Register, if service has already commenced by that date, or the date when service commences, but in no event will the refund effective date be later than five months subsequent to the expiration of the 60-day period.[33]

Section 206(b) also requires that, if no final decision is rendered in the Commission investigation by the refund effective date or by the conclusion of the 180-day period commencing upon initiation of a proceeding pursuant to Section 206, whichever is earliest, the Commission shall state the reasons why it has failed to do so and shall state its best estimate as to when it reasonably expects to make such a decision. To implement that requirement, we will direct the presiding judge to provide a report to the Commission 15 days in advance of the refund effective date in the event the presiding judge has not by that date: (1) certified to the Commission a settlement which, if accepted, would dispose of the proceeding; or (2) issued an initial decision. The judge's report, if required, shall advise the Commission of the status of the investigation and provide an estimate of the expected date of certification of an initial decision or of a settlement.

2. Order No. 614 Compliance

Vermont Yankee has filed eight copies of Amendatory Agreements which, except for having a separate name for each of the Purchasers, are identical, and appear to comport with the requirements of Order No. 614.[34] However, Order No. 614 contemplates that when a sheet or page of a rate schedule is subsequently changed or modified, then that page would be superseded with a new page that contains only the effective language. Rather than superseding pages in their existing Contracts and only using effective language in the Contracts, Vermont Yankee has listed numerous sections in the Contracts that were either deleted or modified and has left the deleted sections in the Amendatory Agreements. Vermont Yankee is hereby directed to file revised Amendatory Agreements that include only the effective language. In addition, Vermont Yankee may want to consider a single Amendatory Agreement along with a customer list, similar to a tariff, rather than filing to eight identical agreements. Finally, if there are any provisions in the Power Sales Agreement that will affect rates, terms or conditions in the Amendatory Agreement, e.g., topping-off the decommissioning fund or sharing additional decommissioning costs if there is a delay, then those provisions should also be incorporated into the Amendatory Agreements.

3. Motions to Consolidate and Coordinate Proceedings

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order. A list of Commission judges and a summary of their background and experience is available at http://www.ferc.gov/legal/oalj/bio/judges.htm.

[33]See Vermont Yankee Nuclear Power Corp., et al., 91 FERC & 61,325 at 62,128 (2000).

[34]Designation of Electric Rate Schedule Sheets, 90 FERC & 61,352 (2000).

Vermont DPS requests that the Commission consolidate the interrelated Docket Nos. EC02-5-000 and ER02-211-000 to be consistent with judicial economy and administrative efficiency.[35] Vermont DPS contends that consolidation would also be consistent with the Commission's prior treatment of the proposed sale of the Plant.[36] Applicants dispute whether the Commission consolidated the proceedings the last time Vermont Yankee attempted to sell the Plant and oppose consolidation because they believe that it could delay closing the sale of the Plant.

We agree with the Applicants. In our prior order, we granted the requisite authorizations under Section 203 of the FPA for the proposed sale to proceed.[37] Specifically, we granted authorization for the sale and transfer of the jurisdictional interconnection facilities and we directed Vermont Yankee to file accounting entries after sale of the Plant. The only discussion on consolidation in that order was related to the electric rate docket (ER00B1027) and the complaint docket (EL00-86).[38] Since we are not setting the disposition of facilities (Section 203) filing for hearing, consolidating it with the Section 205 filing would be fruitless. Therefore, we will deny Vermont DPS's request for consolidation.

Vermont DPS also requests that the Commission establish settlement proceedings to coordinate these jurisdictional proceedings with those of the VPSB. Vermont DPS advises that many issues that it raises here are also raised in the VPSB proceeding and that parties to these proceedings have a long history of resolving issues by settlement. Applicants do not oppose settlement procedures or coordination with the state proceeding. Therefore, consistent with the cases cited by Vermont DPS, we will leave to the discretion of the Presiding Judge, in the hearing we order below, to decide how best to coordinate the investigation with the proceeding in Vermont.

The Commission orders:

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[35] Citing, e.g., Pacific Gas and Electric Co.83 FERC & 61,212 at 61,938 (1998); American Transmission Systems, Inc., et al., 89 FERC & 61,088 at 61,249 (1999).

[36] See Vermont Yankee Nuclear Power Corp., et al., 91 FERC & 61,325 (2000) (involving, in part, Vermont Yankee's sale of certain jurisdictional facilities to AmerGen Vermont and the Vermont Electric Power Company).

[37] See id. at 62,124-126.

[38] See id. at 62,128.

(A) The proposed disposition of jurisdictional facilities is hereby authorized, as discussed in the body of this order.

(B) The Commission retains authority under Section 203(b) of the FPA to issue supplemental orders as appropriate.

(C) Vermont Yankee is hereby directed to notify the Commission within 15 days of the date the sale is consummated and service commences, as discussed within the body of this order.

(D) The foregoing authorization is without prejudice to the authority of this Commission or any other regulatory body with respect to rates, service, accounts, valuation, estimates or determinations of cost, or any other matter whatsoever now pending or which may come before this Commission.

(E) Nothing in this order shall be construed to imply acquiescence in any estimate or determination of cost or any valuation of property claimed or asserted.

(F) Applicants' proposed Amendatory Agreements are accepted for filing, and suspended for a nominal period to become effective on the date service commences, subject to refund and subject to the outcome of Docket No. ER02-564-000 as discussed herein.

(G) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by Section 402(a) of the Department of Energy Organization Act and by the Federal Power Act, particularly Sections 205 and 206 thereof, and pursuant to the Commission's Rules of practice and procedure and the regulations under the Federal Power Act (18 C.F.R. Chapter I), a public hearing shall be held in Docket No. ER02-211-000 concerning the justness and reasonableness of Applicants' rates and rate terms. As discussed in the body of this order, we will hold the hearing in abeyance to give the parties time to conduct settlement judge negotiations.

(H) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by Section 402(a) of the Department of Energy Organization Act and by the Federal Power Act, particularly Section 206 thereof, and pursuant to the Commission's Rules of practice and procedure and the regulations under the Federal Power Act (18 C.F.R. Chapter I), a public hearing shall be held in Docket No. EL02-53-000 concerning the justness and reasonableness of Applicants' rates and rate terms, as discussed in the body of this order.

(I) Pursuant to Rule 603 of the Commission's Rule of Practice and Procedure, 18 C.F.R. ' 385.603 (2001), the Chief Administrative Law Judge is hereby authorized to appoint a settlement judge in this proceeding within 15 days of the date of this order. Such settlement judge shall have all powers and duties enumerated in Rule 603 and shall convene a settlement conference as soon as practicable after the Chief Judge designates the settlement judge. If the parties decide to request a specific judge, they must make their request to the Chief Judge in writing or by telephone within 5 days of the date of this order.

(J) Within 60 days of the date of this order, the settlement judge shall file a report with the Commission and the Chief Judge on the status of the settlement discussions. Based on this report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions, if appropriate, or assign this case to a presiding judge for a formal evidentiary hearing, if appropriate. If settlement discussions continue, the settlement judge shall file a report at least every 60 days thereafter, informing the Commission and the Chief Judge of the parties' progress toward settlement.

(K) If the settlement procedures fail, and a formal hearing is to be held, a presiding judge to be designated by the Chief Judge shall convene a conference in this proceeding to be held within approximately 15 days of the date the Chief Judge designates the presiding judge, in a hearing room of the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426. Such conference shall be held for purpose of establishing a procedural schedule. The presiding judge is authorized to establish procedural dates and to rule on all motions (except motions to dismiss), as provided in the Commission's Rules of Practice and Procedure.

(L) The Secretary shall promptly publish in the Federal Register a notice of the Commission's initiation of the proceeding in Docket No. EL02-53-000.

(M) The refund effective date in Docket No. EL02-53-000, established pursuant to Section 206(b) of the Federal Power Act, will be 60 days following publication in the Federal Register of the notice discussed in Ordering Paragraph (L) above.

(N) Applicants are hereby directed to account for the sale in accordance with the Uniform System of Accounts, and file their journal entries to clear Account 102 within six months of the date the sale of jurisdictional facilities is completed.

(O) Applicants are hereby directed to refile the Amendatory Agreements with all purchasers in compliance with Order No. 614 within 30 days of the order herein.

By the Commission.

(S E A L)

Linwood A. Watson, Jr.,
Deputy Secretary.

Record Request AG-2

Provide a full and complete copy of Attachment AG-1-20(g), the minutes of the Vermont Yankee Board of Directors on August 3, 2001.

Response

Please see Attachment RR-AG-2 ***CONFIDENTIAL***.

The Attachment contains confidential, sensitive and proprietary information, which is the subject of a motion for protected treatment pursuant to G.L. c. 25, § 5D. The PROTECTED MATERIALS will be made available in this proceeding subject to the execution of an appropriate non-disclosure agreement.

Record Request AG-7

Please explain: (1) why draft balance sheets, income statements and statements of cash flow may be a violation of SEC reporting requirements; and (2) update the Vermont Yankee Nuclear Power Corporation 2000 Annual Report to Shareholders (Exhibit AG-1-2(a)) and to the NSTAR 2000 Annual Report to Shareholders (Exhibit AG-1-2(c)), to the extent that such updates exist.

Response

The Vermont Yankee Nuclear Power Corporation 2001 Annual Report to Shareholders and the NSTAR 2001 Annual Report to Shareholders are not publicly available. These reports are expected to be available in April 2001. Preliminary disclosure of financial information that would be contained in those reports would violate Regulation FD of the Securities and Exchange Commission ("SEC") (17 CFR Parts 240, 243, and 249), which prohibits selective disclosure of this type of material, nonpublic information. However, please see Attachment RR-AG-7 for a copy of NSTAR's SEC Form 10-Q for September 2001, which provides an update to NSTAR's 2000 Annual Report to Shareholders. Vermont Yankee does not file a Form 10-Q.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

[x] Quarterly report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended September 30, 2001

or

[ ] Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from __________ to __________

Commission file number 1-14768

NSTAR
(Exact name of registrant as specified in its charter)

Massachusetts (State or other jurisdiction of incorporation or organization)	04-3466300 (I.R.S. Employer Identification No.)
800 Boylston Street, Boston, Massachusetts (Address of principal executive offices)	02199 (Zip Code)

Registrant's telephone number, including area code: (617)424-2000

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at November 1, 2001
Common Shares, $1 par value	53,032,546 shares

Common Shares, $1 par value 53,032,546 shares

Part I - Financial Information
Item 1. Financial Statements

NSTAR
Condensed Consolidated Statements of Income
(Unaudited)
(in thousands, except per share amounts)

	Three Months Ended September 30, 2001	Three Months Ended September 30, 2000	Nine Months Ended September 30, 2001	Nine Months Ended September 30, 2000
Operating revenues	$890,748	$709,519	$2,487,843	$1,998,231
Operating expenses:				
Purchased power and cost of gas sold	524,460	333,885	1,489,595	1,007,898
Operations and maintenance	102,694	96,464	306,020	305,280
Depreciation and amortization	60,470	67,865	174,590	185,832
Demand side management and renewable energy programs	19,824	23,286	58,156	59,014
Property and other taxes	22,485	20,123	72,061	66,868
Income taxes	45,832	41,032	101,493	90,119
Total operating expenses	775,765	582,655	2,201,915	1,715,011
Operating income	114,983	126,864	285,928	283,220
Other income (deductions):				
Write-down of RCN investment, net	-	-	(173,944)	-
Other income, net	(2,005)	(340)	1,041	5,624
	(2,005)	(340)	(172,903)	5,624
Operating and other income	112,978	126,524	113,025	288,844
Interest charges:				
Long term debt	29,548	27,297	88,772	79,817
Transition property securitization certificates	10,337	11,223	31,566	34,625
Other	5,707	22,520	21,694	40,821
Allowance for borrowed funds used during construction	(1,250)	(802)	(3,097)	(2,732)
Total interest charges	44,342	60,238	138,935	152,531
Net income (loss)	68,636	66,286	(25,910)	136,313
Preferred stock dividends of subsidiary	1,490	1,490	4,470	4,470
Earnings (loss) available for common shareholders	$ 67,146	$ 64,796	$(30,380)	$ 131,843
Weighted average common shares outstanding:				
Basic	53,033	53,690	53,033	55,510
Diluted	53,270	53,850	53,205	55,677
Earnings (loss) per common share:				
Basic	$1.27	$1.21	$(0.57)	$2.38
Diluted	$1.26	$1.20	$(0.57)	$2.37

Dividends declared per common share	$0.515	$0.50	$1.545	$1.50

The accompanying notes are an integral part of the condensed consolidated financial statements.

NSTAR
Condensed Consolidated Statements of Comprehensive Income (Loss)
(Unaudited)
(in thousands)

	Three Months Ended September 30, 2001	2000	Nine Months Ended September 30, 2001	2000
Net income (loss)	$68,636	$ 66,286	$(25,910)	$136,313
Other comprehensive income,net:				
Changes in unrealized gain (loss) on investments	(6,185)	(11,147)	35,308	(56,382)
Comprehensive income	$62,451	$ 55,139	$ 9,398	$ 79,931

The accompanying notes are an integral part of the condensed consolidated financial statements.

NSTAR
Condensed Consolidated Statements of Retained Earnings
(Unaudited)
(in thousands)

	Three Months Ended September 30, 2001	2000	Nine Months Ended September 30, 2001	2000
Balance at the beginning of the period	$294,818	$395,086	$447,087	$389,989
Add (Deduct):				
Net income (loss)	68,636	66,286	(25,910)	136,313
Subtotal	363,454	461,372	421,177	526,302
Deduct:				
Dividends declared:				
Common shares	27,312	26,516	81,935	82,003
Preferred stock	1,490	1,490	4,470	4,470
Subtotal	28,006	86,405	86,473	28,802
Provision for preferred stock redemption and issuance costs	60	60	180	180
Common share repurchase program	-	2,507	-	8,850
Balance at the end of the period	$334,592	$430,799	$334,592	$430,799

The accompanying notes are an integral part of the condensed consolidated financial statements.

NSTAR
Condensed Consolidated Balance Sheets
(Unaudited)
(in thousands)

	September 30, 2001	December 31, 2000
Assets		
Utility plant in service, at original cost	$3,804,925	$3,724,754
Less: accumulated depreciation	1,300,197	1,249,685
	2,504,728	2,475,069
Construction work in progress	74,778	48,524
Net utility plant	2,579,506	2,523,593
Non-utility property, net	110,290	105,827
Goodwill	466,689	475,877
Equity investments	24,320	25,791
Other investments	69,457	170,829
Current assets:		
Cash and cash equivalents	23,902	21,873
Restricted cash	23,817	22,152
Accounts receivable, net	616,402	454,499
Regulatory assets	125,988	242,663
Accrued unbilled revenues	58,446	101,732
Fuel, materials and supplies, at average cost	48,751	44,659
Other	35,323	32,447
Total current assets	932,629	920,025
Deferred debits:		
Regulatory assets	982,797	1,029,341
Prepaid pension expense	179,757	149,890
Other	124,461	146,542
Total assets	$5,469,906	$5,547,715

The accompanying notes are an integral part of the condensed consolidated financial statements.

NSTAR
Condensed Consolidated Balance Sheets
(Unaudited)
(in thousands)

	September 30, 2001	December 31, 2000
Capitalization and Liabilities		
Common equity:		
Common shares, par value $1 per share (53,032,546 shares issued and outstanding)	$ 53,033	$ 53,033
Premium on common shares	877,066	876,749
Retained earnings	334,592	446,587
Total common equity	1,264,691	1,376,369

Accumulated other comprehensive income (loss)	1,164	(34,144)
Cumulative nonmandatory redeemable Preferred stock	43,000	43,000
Long-term debt	1,380,775	1,440,431
Transition property securitization certificates	513,904	584,130
Total long-term debt	1,894,679	2,024,561
Total capitalization	3,203,534	3,409,786
Current liabilities:		
Long-term debt and preferred stock due within one year	91,271	58,695
Transition property securitization certificates due within one year	59,041	36,443
Notes payable	644,147	468,347
Accounts payable	178,108	275,778
Deferred taxes	67,402	128,788
Accrued interest	15,220	44,220
Dividends payable	28,305	28,305
Other	354,983	301,873
Total current liabilities	1,438,477	1,342,449
Deferred credits:		
Accumulated deferred income taxes	570,767	537,756
Accumulated deferred investment tax credits	38,476	39,960
Other	218,652	217,764
Total deferred credits	827,895	795,480
Commitments and contingencies		
Total capitalization and liabilities	$5,469,906	$5,547,715

The accompanying notes are an integral part of the condensed consolidated financial statements.

NSTAR
Condensed Consolidated Statements of Cash Flows
(Unaudited)
(in thousands)

	Nine Months Ended September 30, 2001	2000
Operating activities:		
Net (loss) income	$(25,910)	$ 136,313
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	174,590	185,832
Deferred income taxes and investment tax credits	(50,457)	45,317
Loss on write-down of RCN investment	168,376	-
Allowance for borrowed funds used during construction	(3,097)	(2,732)
Net changes in working capital	(87,249)	(142,110)
Other, net	(40,876)	(163,959)

Other, net	(40,876)	(163,959)
Net cash provided by operating activities	135,377	58,661
Investing activities:		
Plant expenditures (excluding AFUDC)	(149,506)	(121,340)
Other investments	1,471	(59,393)
Net cash used in investing activities	(148,035)	(180,733)
Financing activities:		
Common share repurchases	-	(212,039)
Long-term debt redemptions	(27,080)	(201,886)
Transition property securitization certificates redemptions	(47,628)	(82,149)
Long-term debt issue	-	500,000
Net change in notes payable	175,800	57,552
Dividends paid	(86,405)	(84,468)
Net cash provided by (used in) financing activities	14,687	(22,990)
Net increase (decrease) in cash and cash equivalents	2,029	(145,062)
Cash and cash equivalents at beginning of year	21,873	168,599
Cash and cash equivalents at end of period	$ 23,902	$ 23,537
Supplemental disclosures of cash flow information:		
Cash paid during the period for:		
Interest, net of amounts capitalized	$ 145,897	$ 127,988
Income taxes	$ 141,907	$ 20,835
Supplemental disclosure of investing activity:		
Investment in common shares	$ 4,537	$ -

The accompanying notes are an integral part of the condensed consolidated financial statements.

Notes to Unaudited Condensed Consolidated Financial Statements

The accompanying Notes should be read in conjunction with Notes to the Consolidated Financial Statements incorporated in NSTAR's 2000 Annual Report on Form 10-K.

A) About NSTAR

NSTAR is an energy delivery company serving approximately 1.3 million customers in Massachusetts including more than one million electric customers in 81 communities and 244,000 gas customers in 51 communities. NSTAR's retail utility subsidiaries are Boston Edison Company (Boston Edison), Commonwealth Electric Company (ComElectric), Cambridge Electric Light Company (Cambridge Electric) and NSTAR Gas Company (NSTAR Gas). Its wholesale electric subsidiary is Canal Electric Company (Canal Electric). NSTAR's three retail electric companies operate under the brand name "NSTAR Electric." Reference in this report to "NSTAR Electric" shall mean each of Boston Edison, ComElectric and Cambridge Electric. NSTAR's non-utility operations include telecommunications - NSTAR Communications, Inc. (NSTAR Com), district heating and cooling operations (Advanced Energy Systems, Inc. and NSTAR Steam Corporation) and a liquefied natural gas

Inc. and NSTAR Steam Corporation) and a liquefied natural gas service (Hopkinton LNG Corp.).

B) Basis of Presentation

The financial information presented as of September 30, 2001 and for the periods ended September 30, 2001 and 2000 have been prepared from NSTAR's books and records without audit by independent accountants. Financial information as of December 31, 2000 was derived from the audited consolidated financial statements of NSTAR, but does not include all disclosures required by generally accepted accounting principles (GAAP). In the opinion of NSTAR's management, all adjustments (which are of a normal recurring nature) necessary for a fair presentation of the financial information for the periods indicated have been included. Certain reclassifications have been made to the prior year data to conform with the current presentation.

The preparation of financial statements in conformity with GAAP requires management of NSTAR and its subsidiaries to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from these estimates.

The results of operations for the periods ended September 30, 2001 and 2000 are not indicative of the results that may be expected for an entire year. Kilowatt-hour sales and revenues are typically higher in the winter and summer than in the spring and fall, as sales tend to vary with weather conditions. Higher usage levels during the summer period, combined with Boston Edison's higher summer period seasonal rates, have had a significant impact on the results of operations for this period. In general, during periods of high demand, the impact on revenues and expenses can be significant when combined with higher seasonal demand rates. Gas sales and revenues are typically higher in the winter months than during other periods of the year.

NSTAR Electric experienced a new single hour peak load on August 9, 2001 of 4,527 megawatts (MW) that exceeded the prior peak load of 4,174 MW by 8.5% experienced in 1999.

C) Employee Relations

A collective bargaining unit contract representing approximately 300 NSTAR Gas employees expires March 31, 2002. NSTAR management is currently involved in discussions with Local 12004, United Steelworkers of America, AFL-CIO regarding a new contract. Management believes it has satisfactory employee relations with a significant majority of its employees.

D) Goodwill

In July 2001, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards (SFAS) No. 142, "Goodwill and Other Intangible Assets" (SFAS 142). This statement, which is effective for fiscal years beginning after December 15, 2001, establishes accounting and reporting standards for acquired goodwill and other intangible assets. NSTAR will adopt SFAS 142 in the first quarter of 2002. SFAS 142 states that goodwill shall not be amortized and shall be tested for impairment on an annual basis. Management is currently assessing the impact of SFAS 142 in light of its existing regulatory rate the impact of SFAS 142 in light of its existing regulatory rate plan and requirements of SFAS 142. Therefore, NSTAR is unable to reasonably estimate the impact of the adoption of this statement.

E) RCN Joint Venture and Investment Conversion

NSTAR Com is a participant in a telecommunications venture with RCN Telecom Services, Inc. of Massachusetts, a subsidiary of RCN Corporation (RCN). NSTAR Com has accounted for its equity investment in the joint venture using the equity method of accounting. As part of the Joint Venture Agreement, NSTAR Com has the option to exchange portions of its joint venture interest for common shares of RCN at specified periods. To date, NSTAR Com has received approximately 4.1 million shares of RCN common shares from prior exchanges of its joint venture interest.

On April 6, 2000, NSTAR Com issued its third and final notice to exchange substantially all of its remaining interest in the joint venture into common shares of RCN. Effective with the third notice, NSTAR Com's profit and loss sharing ratio was reduced to zero. Therefore, NSTAR Com no longer recognized any results of operations of the joint venture. During the period January 1, 2000 through April 6, 2000, NSTAR Com recognized $5.6 million in equity losses from the joint venture and has not recorded any further joint venture losses since that date.

On October 18, 2000, NSTAR Com and RCN signed an agreement in principle to amend the Joint Venture Agreement. Among other items, this proposal settled the number of shares to be received for the third conversion of NSTAR Com's remaining equity investment at 7.5 million shares. Management anticipates having a final amended Joint Venture Agreement in place by the end of 2001.

As previously disclosed, management continues to evaluate the carrying value of its entire investment in RCN. Consistent with the performance of the telecommunications sector as a whole, the market value of RCN's common shares has decreased significantly over the past several quarters. Management determined that this decline in market value is "other-then-temporary" in accordance with the SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities."

In addition, during the first quarter of 2001, the status of the amendment to the Joint Venture Agreement with RCN regarding the 7.5 million shares, led management to determine that its investment in the joint venture was also impaired based on future market expectations for RCN common shares related to this investment.

Therefore, NSTAR Com, recognized an impairment of its entire investment in RCN in the first quarter of 2001. This write-down resulted in an one-time, non-cash, after-tax charge of $173.9 million that is reported on the accompanying Condensed Consolidated Statements of Income as "Write-down of RCN Investment, net."

The RCN shares received, as well as the remaining interest in the joint venture related to the pending 7.5 million shares, are included in Other investments on the accompanying Condensed Consolidated Balance Sheets at their estimated fair value of approximately $41.2 million at September 30, 2001. The fair value of the shares currently held may increase or decrease, at any time, as a result of changes in the market value of RCN common shares. The unrealized gain or loss associated with shares currently held will fluctuate due to the changes in fair shares currently held will fluctuate due to the changes in fair value of these shares during each period and is reflected, net of associated income taxes, as a component of Other comprehensive income, net on the accompanying Condensed Consolidated Statements of Comprehensive Income (Loss). The cumulative increase or decrease in fair value of these shares as of September 30, 2001 reflect the change since the write-down of these shares as a component of Accumulated other comprehensive income (loss) on the accompanying Condensed Consolidated Balance Sheets. Management will continue to evaluate the carrying value of its investment in RCN.

At September 30, 2001 and December 31, 2000, NSTAR Com had $5.1 million and $47.9 million, respectively, in accounts receivable due from the joint venture. This is primarily the result of construction performed on behalf of the joint venture.

F) Other Investments

In the second quarter of 2001, NSTAR completed its determination of the accounting for equity securities it previously received in connection with the demutualization of John Hancock Mutual Life Insurance Company and Metropolitan Life Insurance Company. NSTAR and its subsidiaries, as policyholders, received a distribution of common stock of each company. As a result, NSTAR recognized $4.5 million of other income on these transactions.

These securities are currently available for sale and are included in Other investments on the accompanying Condensed Consolidated Balance Sheets. The value of these common shares was adjusted to reflect market values as of September 30, 2001. The unrealized gain or loss associated with these shares will fluctuate due to changes in current market values and is reflected, net of associated income taxes, as a component of Other comprehensive income, net on the accompanying Condensed Consolidated Statements of Comprehensive Income (Loss). The cumulative increase or decrease in fair value of these shares as of September 30, 2001 is reflected as a component of Accumulated other comprehensive income (loss) on the accompanying Condensed Consolidated Balance Sheets.

G) Income Taxes

The following table reconciles the statutory federal income tax rate to the annual estimated effective income tax rate for 2001 and the actual effective income tax rate for the year ended December 31, 2000:

	2001	2000
Statutory tax rate	35.0%	35.0%
State income tax, net of federal income tax benefit	5.6	5.1
Investment tax credits	(1.3)	(0.6)
Other	2.3	2.1
Effective tax rate before write-down of RCN	41.6	41.6
Write-down of RCN investment (federal and state)	53.5	-
Effective tax rate	95.1%	41.6%
	=====	=====

Income tax expense includes $5.6 million related to the write-down of the RCN investment, net as reflected on the accompanying Condensed Consolidated Statements of Income. This $5.6 million charge was recognized due to the fact that NSTAR Com had recorded a deferred tax asset in excess of what is currently deemed realizable. In addition, NSTAR Com has determined that no current tax benefit is anticipated on the write-down of its remaining joint venture investment. Therefore, NSTAR Com has recorded a $64.5 million valuation allowance for the entire tax benefit related to the write-down of its RCN investment. If all or a portion of these tax benefits are ultimately realized, NSTAR Com will reflect a corresponding reduction in income tax expense.

H) Earnings Per Common Share

Basic earnings per common share (EPS) is calculated by dividing net income, after deductions for preferred dividends, by the weighted average common shares outstanding during the year. Statement of Financial Accounting Standards No. 128, "Earnings per Share," requires the disclosure of diluted EPS. Diluted EPS is similar to the computation of basic EPS except that the weighted average common shares is increased to include the number of dilutive potential common shares. Diluted EPS reflects the impact on shares outstanding of the deferred (nonvested) shares and stock options granted under the NSTAR Stock Incentive Plan. The following table summarizes the reconciling amounts between basic and diluted EPS:

(in thousands, except per share amounts)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2001	2000	2001	2000
Before one-time RCN charge:				
Earnings available for common shareholders	$ 67,146	$ 64,796	$ 143,564	$ 131,843
Basic EPS	$1.27	$1.21	$2.71	$2.38
Diluted EPS	$1.26	$1.20	$2.70	$2.37
After one-time RCN charge:				
Earnings (loss) available for common shareholders	$ 67,146	$ 64,796	$ (30,380)	$ 131,843
Basic EPS	$1.27	$1.21	$(0.57)	$2.38
Diluted EPS	$1.26	$1.20	$(0.57)	$2.37
Weighted average common shares outstanding for basic EPS	53,033	53,690	53,033	55,510
Effect of diluted shares:				
Weighted average dilutive potential common shares	237	160	172	167
Weighted average common shares outstanding for diluted EPS	53,270	53,850	53,205	55,677

I) Contingencies

1. Environmental Matters

NSTAR's subsidiaries are involved in approximately 25 state-regulated properties where oil or other hazardous materials were previously spilled or released. The companies are required to clean up these properties in accordance with specific state regulations. There are uncertainties associated with these costs due to the complexities of cleanup technology, regulatory requirements and the particular characteristics of the different sites. NSTAR subsidiaries also face possible liability as a potentially responsible party (PRP) in the cleanup of seven multi-party hazardous waste sites in Massachusetts and other states party hazardous waste sites in Massachusetts and other states where it is alleged to have generated, transported or disposed of hazardous waste at the sites. NSTAR generally expects to have only a small percentage of the total potential liability for these sites. Approximately $5.9 million and $7 million are included as liabilities in the accompanying Condensed Consolidated Balance Sheets at September 30, 2001 and December 31, 2000, respectively, related to the non-recoverable portion of these cleanup liabilities. Management is unable to fully determine a range of reasonably possible cleanup costs in excess of the accrued amount. Based on its assessments of the specific site circumstances, management does not believe that it is probable that any such additional costs will have a material impact on NSTAR's consolidated financial position. However, it is reasonably possible that additional provisions for cleanup costs that may result from a change in estimates could have a material impact on the results of operations for a reporting period in the near term.

NSTAR Gas is participating in the assessment of a number of former manufactured gas plant (MGP) sites and alleged MGP waste disposal locations to determine if and to what extent such sites have been contaminated and whether NSTAR Gas may be responsible for remedial action. The MDTE has approved recovery of costs associated with MGP sites. As of September 30, 2001, NSTAR Gas has recorded a liability of $7.2 million as an estimate for site cleanup costs for several MGP sites for which NSTAR Gas was previously cited as a PRP.

Estimates related to environmental remediation costs are reviewed and adjusted periodically as further investigation and assignment of responsibility occurs. NSTAR is unable to estimate its ultimate liability for future environmental remediation costs. However, in view of NSTAR's current assessment of its environmental responsibilities, existing legal requirements and regulatory policies, management does not believe that these matters will have a material adverse effect on NSTAR's consolidated financial position or results of operations for a reporting period.

2. Industry and Corporate Restructuring Legal Proceedings

The MDTE order approving the Boston Edison electric restructuring settlement agreement was appealed by certain parties to the Massachusetts Supreme Judicial Court. One appeal remains pending. However, there has to date been no briefing, hearing or other action taken with respect to this proceeding. However, if an unfavorable outcome were to occur, there could be a material adverse impact on business operations, the consolidated financial position, cash flows and the results of operations for a reporting period.

The MDTE order approving the rate plan associated with the merger of BEC and COM/Energy was appealed by certain parties to the Massachusetts Supreme Judicial Court. The appeals of the Massachusetts Attorney General and a separate group that consists of The Energy Consortium, Harvard University and Associated Industries of Massachusetts remain pending. In October 2001, the MDTE certified the record of the case to the court; however, there has to date been no briefing, hearing or other action taken with respect to this proceeding. If an unfavorable outcome were to occur, there could be a material adverse impact on business operations, the consolidated financial position, cash flows and the results of operations for a reporting period.

3. Regulatory Proceedings

3. Regulatory Proceedings

On June 1, 2001, the MDTE issued its final orders on the reconciliation of ComElectric and Cambridge Electric's transition, standard offer service, default service and transmission costs and revenues for 1999.

In a Boston Edison 1999 reconciliation filing with the MDTE, the Massachusetts Attorney General contested cost allocations related to Boston Edison's wholesale customers since 1998. On June 1, 2001, the MDTE approved Boston Edison's revenue-credit approach for wholesale sales to be consistent with Boston Edison's restructuring settlement. The reconciliation of wholesale revenues and costs, along with other reconciliation issues are addressed in Boston Edison's outstanding filing covering the reconciliation of costs through December 31, 2000. On October 19, 2001, Boston Edison and the Massachusetts Attorney General filed a proposed Settlement Agreement with the MDTE resolving all outstanding issues in this filing. This settlement agreement did not have a material effect on NSTAR's consolidated financial position or results of operations.

In October 1997, the MDTE opened a proceeding to investigate Boston Edison's compliance with a 1993 order that permitted the formation of Boston Energy Technology Group and authorized Boston Edison to invest up to $45 million in non-utility activities. Hearings were completed during 1999. Management is currently unable to determine the timing and outcome of this proceeding. However, if an unfavorable outcome were to occur, there could be a material adverse impact on business operations, the consolidated financial position, cash flows and results of operations for a reporting period.

On June 13, 2001, the MDTE approved a settlement agreement between Cambridge Electric and the Massachusetts Institute of Technology (MIT) involving a dispute over the customer transition charge (CTC) assessed by Cambridge Electric to MIT. Under the settlement, Cambridge Electric has refunded approximately $1.7 million to MIT and MIT has withdrawn (i) its appeal at the Massachusetts Supreme Judicial Court of the MDTE's rate order associated with the merger of BEC Energy and COM/Energy and (ii) its separate rate complaint at the MDTE involving the CTC.

On October 29, 2001, NSTAR Electric and NSTAR Gas filed with the MDTE a proposed service quality plan, which replaced the plan that had previously been filed as a part of the NSTAR merger rate plan and which implemented guidelines that had been established by the MDTE as a result of its generic investigation of service quality issues. The service quality plan would establish performance benchmarks effective January 1, 2002 for certain identified measures of service quality relating to customer service and billing performance, customer satisfaction and reliability and safety performance. The companies are required to report annually concerning their performance as to each measure and would be subject to penalties of up to two percent of transmission and distribution revenues should performance fail to meet the applicable benchmarks. On the same date, NSTAR Electric and NSTAR Gas also filed with the MDTE a report concerning their performance on the identified service quality measures for the two twelve month periods ended August 31, 2000 and 2001. This report included a calculation of penalties in accordance with MDTE guidelines whereby penalties were calculated relating primarily to Boston Edison electric system reliability performance for the summer of 2001 totaling approximately $3.9 million. NSTAR disputes the legal applicability of penalties for these performance periods; however proposed in settlement of this these performance periods; however proposed in settlement of this matter to provide credits to Boston Edison customers totaling $3.9 million, offset in part by other payments to Boston Edison customers, which have totaled approximately $1.1 million to date, relating to summer 2001 electric service outages.

Also on October 29, 2001, NSTAR Electric filed with the MDTE a comprehensive report regarding electric system performance issues experienced during the summer of 2001. The filing included detailed analyses of factors affecting performance, as well as, the companies' plans to address issues identified. The MDTE has also requested similar filings from other Massachusetts electric distribution companies and has stated that they intend to hold public hearings and adjudicatory hearings concerning each such filing. NSTAR is unable to estimate its ultimate liability for future costs as a result of such proceeding. However, in view of NSTAR's current assessment of its electric distribution system performance responsibilities, existing legal requirements and regulatory policies, management does not believe that these matters will have a material adverse effect on NSTAR's consolidated financial position or results of operations for a reporting period.

4. Other Litigation

In the normal course of its business, NSTAR and its subsidiaries are also involved in certain other legal matters. Management is unable to fully determine a range of reasonably possible legal costs in excess of amounts accrued. Based on the information currently available, it does not believe that it is probable that any such additional costs will have a material impact on its consolidated financial position.

J) Segment and Related Information

For the purpose of providing segment information, NSTAR's principal operating segments, or its traditional core businesses, are the electric and natural gas utilities that provide energy delivery services in over 100 cities and towns in Massachusetts. NSTAR subsidiaries also supply electricity at wholesale to municipalities. The non-utility operating segments engage in business activities that include telecommunications, district heating and cooling operations, and a liquefied natural gas service.

Financial data for the operating segments are as follows:

(in thousands)	Utility Operations Electric	Gas	Non-utility Operations	Consolidated Total
Three months ended -				
September 30, 2001				
Operating revenues	$ 822,475	$ 41,014	$ 27,259	$ 890,748
Segment net income (loss)	$ 81,122	$ (4,908)	$ (7,578)	$ 68,636
September 30, 2000				
Operating revenues	$ 608,391	$ 47,641	$ 53,487	$ 709,519
Segment net income (loss)	$ 79,447	$ (4,144)	$ (9,017)	$ 66,286
Nine months ended -				
September 30, 2001				
Operating revenues	$ 2,099,292	$303,822	$ 84,729	$2,487,843
Segment net income (loss)	$ 151,113	$ 10,505	$(187,528)	$ (25,910)
September 30, 2000				

Operating revenues	$ 1,666,384	$242,050	$ 89,797	$1,998,231
Segment net income (loss)	$ 135,956	$ 13,900	$ (13,543)	$ 136,313
Total assets				
September 30, 2001	$ 4,615,914	$497,478	$ 356,514	$5,469,906
December 31, 2000	$ 4,529,014	$534,430	$ 484,271	$5,547,715

Item 2. Management's Discussion and Analysis

NSTAR is an energy delivery company serving approximately 1.3 million customers in Massachusetts including more than one million electric customers in 81 communities and 244,000 gas customers in 51 communities. NSTAR's retail utility subsidiaries are Boston Edison Company (Boston Edison), Commonwealth Electric Company (ComElectric), Cambridge Electric Light Company (Cambridge Electric) and NSTAR Gas Company (NSTAR Gas). Its wholesale electric subsidiary is Canal Electric Company (Canal Electric). NSTAR's three retail electric companies operate under the brand name "NSTAR Electric." Reference in this report to "NSTAR Electric" shall mean each of Boston Edison, ComElectric and Cambridge Electric. NSTAR's non-utility operations include telecommunications - NSTAR Communications, Inc. (NSTAR Com), district heating and cooling operations (Advanced Energy Systems, Inc. and NSTAR Steam Corporation) and a liquefied natural gas service (Hopkinton LNG Corp.).

The electric and natural gas industries have continued to change in response to legislative, regulatory and marketplace demands for improved customer service at lower prices. These demands have resulted in an increasing trend in the industry to seek competitive advantages and other benefits through business combinations. NSTAR was created to operate in this new marketplace by combining the resources of its utility subsidiaries and concentrating its activities in the transmission and distribution of energy.

The results of operations for the periods ended September 30, 2001 and 2000 are not indicative of the results that may be expected for an entire year. Kilowatt-hour sales and revenues are typically higher in the winter and summer than in the spring and fall, as sales tend to vary with weather conditions. Higher usage levels during the summer period, combined with Boston Edison's higher summer period seasonal rates, have had a significant impact on the results of operations for this period. In general, during periods of high demand, the impact on revenues and expenses can be significant when combined with higher seasonal demand rates. Gas sales and revenues are typically higher in the winter months than during other periods of the year.

NSTAR Electric experienced a new single hour peak load on August 9, 2001 of 4,527 megawatts (MW) that exceeded the prior peak load of 4,174 MW by 8.5% experienced in 1999.

Generating Assets Divestiture

On October 26, 2000, the MDTE approved the filing made by Cambridge Electric and ComElectric (together, "the Companies") for the partial buydown of their contract with Canal Electric for power from the Seabrook nuclear generating facility (Seabrook Contract). The buydown transaction was effected by means of an amendment to the Seabrook Contract. In November 2000, a total of $141.6 million of funds held by an affiliate, Energy Investment Services, Inc. (EIS), was transferred to ComElectric and

Services, Inc. (EIS), was transferred to ComElectric and Cambridge Electric. EIS was established as the vehicle to invest the net proceeds from the sale of the Companies' generation assets. The Companies, in turn, reduced their respective future costs to be recovered from customers. The Federal Energy Regulatory Commission and the MDTE approved Canal's request to amend the Seabrook Contract on March 6, 2001 and May 16, 2001, respectively, to reflect the buydown effective November 1, 2000. Canal, along with other joint-owners of Seabrook, will begin to actively market the sale of Seabrook to other potential buyers.

Retail Electric Rates

On June 13, 2001, the MDTE approved a settlement agreement between Cambridge Electric and the Massachusetts Institute of Technology (MIT) involving a dispute over the customer transition charge (CTC) assessed by Cambridge Electric to MIT. Under the settlement, Cambridge Electric has refunded approximately $1.7 million to MIT and MIT has withdrawn (i) its appeal at the Massachusetts Supreme Judicial Court of the MDTE's rate order associated with the merger of BEC Energy and COM/Energy and (ii) its separate rate complaint at the MDTE involving the CTC.

On October 29, 2001, NSTAR Electric and NSTAR Gas filed with the MDTE a proposed service quality plan, which replaced the plan that had previously been filed as a part of the NSTAR merger rate plan and which implemented guidelines that had been established by the MDTE as a result of its generic investigation of service quality issues. The service quality plan would establish performance benchmarks effective January 1, 2002 for certain identified measures of service quality relating to customer service and billing performance, customer satisfaction and reliability and safety performance. The companies are required to report annually concerning their performance as to each measure and would be subject to penalties of up to two percent of transmission and distribution revenues should performance fail to meet the applicable benchmarks. On the same date, NSTAR Electric and NSTAR Gas also filed with the MDTE a report concerning their performance on the identified service quality measures for the two twelve month periods ended August 31, 2000 and 2001. This report included a calculation of penalties in accordance with MDTE guidelines whereby penalties were calculated relating primarily to Boston Edison electric system reliability performance for the summer of 2001 totaling approximately $3.9 million. NSTAR disputes the legal applicability of penalties for these performance periods; however proposed in settlement of this matter to provide credits to Boston Edison customers totaling $3.9 million, offset in part by other payments to Boston Edison customers, which have totaled approximately $1.1 million to date, relating to summer 2001 electric service outages.

Also on October 29, 2001, NSTAR Electric filed with the MDTE a comprehensive report regarding electric system performance issues experienced during the summer of 2001. The filing included detailed analyses of factors affecting performance, as well as, the companies' plans to address issues identified. The MDTE has also requested similar filings from other Massachusetts electric distribution companies and has stated that they intend to hold public hearings and adjudicatory hearings concerning each such filing. NSTAR is unable to estimate its ultimate liability for future costs as a result of such proceeding. However, in view of NSTAR's current assessment of its electric distribution system performance responsibilities, existing legal requirements and regulatory policies, management does not believe that these matters will have a material adverse effect on NSTAR's consolidated financial position or results of operations for a consolidated financial position or results of operations for a reporting period.

The 1997 Massachusetts Electric Restructuring Act (Restructuring Act) requires electric distribution companies to obtain and resell power to retail customers who choose not to buy energy from a competitive energy supplier through either standard offer service or default service. As a result of the Restructuring Act, standard offer customers of the retail electric subsidiaries of NSTAR currently pay rates that are 15% lower, on an inflation-adjusted basis, than rates in effect prior to March 1, 1998, the retail access date. All distribution customers must pay a transition charge as a component of their rate.

From March 1, 1998, NSTAR Electric's accumulated cost to provide default and standard offer service was in excess of the revenues it was allowed to bill. As a result, NSTAR recorded a regulatory asset of approximately $242.7 million at December 31, 2000 that is reflected as a component of Current assets on the accompanying Condensed Consolidated Balance Sheets. As a result of new rates for standard offer and default service that became effective January 1 and July 1, 2001, the regulatory asset has declined to $126 million as of September 30, 2001.

The retail electric subsidiaries of NSTAR must, on an annual basis, file a forecast reconciliation of their rates for the upcoming year along with any proposed adjustments of prior year revenues and costs for standard offer, default service, transmission and transition charges. The MDTE will, in the ordinary course, approve rates for the coming year before the current year-end to allow the new rates to become effective the first of January. Subsequently, the estimates for the prior year are trued-up to the actual amounts for that year. The MDTE reviews these costs and approves the amounts subject to any required adjustments.

In November 2000, the retail electric subsidiaries of NSTAR made filings containing proposed rate adjustments for 2001, including a reconciliation of costs and revenues through 2000. The MDTE subsequently approved Tariffs for each retail electric subsidiary effective January 1, 2001. The filings were updated in April 2001 to include final costs for 2000, and were further updated in July 2001 to reflect the results of MDTE orders regarding prior year reconciliation proceedings for each company. The MDTE has not yet ruled on the reconciliation component of each of these filings; however on October 19, 2001, Boston Edison and the Massachusetts Attorney General filed a proposed Settlement Agreement with the MDTE resolving all outstanding issues in Boston Edison's reconciliation filing. As a part of this settlement, Boston Edison agreed to reduce the costs sought to be collected through the transition charge by approximately $2.9 million as compared to the amounts that were originally sought. A reserve was established in a prior period and this settlement will not have a material adverse effect on NSTAR's consolidated financial position or results of operations. Management is unable to determine the outcome of the remaining MDTE proceedings. However, based upon past procedures and on information currently available, management does not believe that it is probable that the final MDTE approval will have a material adverse impact on NSTAR's consolidated financial position, results of operations and cash flows in the near term.

In addition to the annual rate filings referenced above, NSTAR Electric also made interim filings with the MDTE concerning charges for a standard offer fuel adjustment and for (market-based) default service rates. In December 2000, the MDTE based) default service rates. In December 2000, the MDTE approved an increase of 1.321 cents per kilowatt-hour (kWh) in each company's standard offer service rates for the first-half of 2001, and in June 2001, the MDTE approved an additional increase of 1.23 cents per kWh effective July 1, 2001 based on a fuel adjustment formula contained in its standard offer tariffs that reflects the prices of natural gas and oil. The MDTE has ruled that these fuel adjustments are excluded from the 15% rate reduction requirement under the Restructuring Act. The MDTE will re-examine these rates before the end of the year for changes to take effect in January 2002.

In October 2001, the MDTE approved market-based default service rates for each company for 2002. Future prices for default service are based upon market solicitations for power supply. NSTAR has entered into power purchase agreements to meet its entire default service supply obligations through December 31, 2002. NSTAR Electric will continue to make market solicitations for default service power supply consistent with provisions of the Restructuring Act and MDTE orders.

The cost of providing standard offer and default service, which includes purchased power costs, is recovered from customers on a fully reconciling basis.

Long-Term Power Purchase Contracts

NSTAR Electric has existing long-term power purchase agreements (PPAs). These long-term contracts are expected to supply approximately 90%-95% of its year 2001 standard offer service obligations. NSTAR Electric has entered into shorter-term agreements to meet the remaining standard offer service obligation. Resulting from a July 2001 request for proposals for standard offer and wholesale service requirements in excess of that provided by its PPAs, NSTAR Electric entered into a letter agreement in September 2001 for service commencing January 1, 2002 for a term of one year.

Natural Gas Industry Restructuring and Rates

Effective November 1, 2000, the MDTE approved regulations that provide for full customer choice to LDCs (local distribution companies) such as NSTAR Gas. NSTAR Gas has modified its billing, customer and gas supply systems to accommodate full retail choice. The MDTE previously had approved the compliance process submitted by NSTAR Gas and other LDCs that implement the unbundling of retail gas services to all customers. Among the important provisions are: setting the LDC as the default service provider, certification of competitive suppliers/marketers, extension of the MDTE's consumer protection rules to residential customers taking competitive service, requirement for LDCs to provide suppliers/marketers with customer usage data, and requirement for suppliers/marketers to disclose service terms to potential customers. The MDTE has also ruled on requiring the mandatory assignment of the LDC's upstream pipeline and storage capacity and downstream peaking capacity to customers who elect a competitive gas supply during a three-year transition period. This eliminates potential stranded cost exposure for the LDCs until they are relieved from their responsibility as suppliers of last resort and the establishment of a "workably competitive" interstate pipeline capacity market. Gas restructuring is not likely to have a significant financial impact on LDCs.

NSTAR Gas' tariffs include a seasonal Cost of Gas Adjustment Clause (CGAC) and a Local Distribution Adjustment Clause (LDAC). The CGAC provides for the recovery of all gas supply costs from

The CGAC provides for the recovery of all gas supply costs from firm sales customers or default service customers. The LDAC provides for the recovery of certain costs applicable to both sales and transportation customers. The CGAC is filed semi-annually for approval by the MDTE. The LDAC is filed annually for approval.

NSTAR Gas' sales are positively impacted by colder weather because a substantial portion of its customer base uses natural gas for space heating purposes.

In December 2000 and in a revised filing in January 2001, NSTAR Gas filed for interim increases to its CGAC for the period February through April 2001 in order to recover significant increases in the costs to buy natural gas supplies. These filings were made to ensure that prices to customers are set at levels that recover all incurred costs in order to avoid the accumulation of significant under-recoveries that would impair NSTAR Gas' ability to serve its customers. On January 31, 2001, the MDTE approved an adjustment to increase the CGAC factor to $1.1123 per therm from the prior factor of $0.7608 per therm. Subsequently, on February 28, 2001, as a result of a decline in wholesale natural gas prices, NSTAR Gas received approval from the MDTE to reduce the factor per therm to $0.9372 effective March 1, 2001, and in conjunction with its semi-annual filing made on March 15, 2001, NSTAR Gas proposed a CGAC factor of $0.7754 per therm for the period commencing May 1, 2001 through October 31, 2001. This factor, approved by the MDTE, included the collection in the summer period of a portion of the coming winter's gas costs in order to reduce cost deferrals that were projected for the end of October 2001. On September 12, 2001 in its semi-annual filing, NSTAR Gas proposed a CGAC factor of $0.526 per therm for the period commencing November 1, 2001 through April 30, 2002. This factor reflected the continuing decline in wholesale natural gas prices and was set to recover outstanding deferral balances. The factor was approved by the MDTE on October 31, 2001.

Results of Operations - Three Months Ended September 30, 2001 vs. Three Months Ended September 30, 2000

Earnings per common share were as follows:

	Three Months Ended September 30, 2001	2000	% Change
Basic	$1.27	$1.21	5%
Diluted	$1.26	$1.20	5%

Earnings were $67.1 million, or $1.27 and $1.26 per basic and diluted common share, respectively, for the third quarter of 2001 compared to $64.8 million, or $1.21 and $1.20 per basic and diluted common share, respectively, in the same period of 2000. Factors that contributed to the $2.3 million improvement in earnings include an increase of 4.2% in retail electric sales and a reduction in other interest charges resulting from a reconciliation of certain regulatory deferrals that resulted in additional regulatory interest expense recorded in 2000. These factors were partially offset by an increase in operations and maintenance expenses of approximately $6.2 million and a reduction in mitigation incentives revenues. Firm gas energy sales were at approximately the same level as in the three-month period of the prior year.

Earnings per common share for the third quarter of 2001 reflect a lower level of common shares outstanding resulting from the repurchase of approximately 1.5 million shares completed in the third quarter of 2000 that had a positive impact of approximately two cents per share. The results of operations for the three-month period ended September 30, 2001 are not indicative of the results that may be expected for the entire year due to the seasonality of electric and gas sales and revenues. Refer to Note B to the Unaudited Condensed Consolidated Financial Statements.

Operating revenues

Operating revenues increased 26% during the third quarter of 2001 as follows:

(in thousands)	
Retail electric revenues	$ 169,380
Wholesale electric revenues	2,474
Gas revenues	(576)
Other revenues	9,951
Increase in operating revenues	$ 181,229

Retail electric revenues were $771.1 million in the third quarter of 2001 compared to $601.8 million in the same period of 2000, an increase of $169.3 million, or 28%. The change in retail revenues includes a 4.2% increase in retail kWh sales, higher rates implemented in January and July 2001 for standard offer and default services ($177.2 million), a net increase in distribution revenue of $4.9 million and transmission revenues of $18.1 million. Included in the change in net distribution revenues is a decrease in incentive revenue entitlements of $20.6 million that Boston Edison receives for successfully lowering transition charges. During 2000, Boston Edison recognized mitigation incentive revenues related to 1998 and 1999. The increase in NSTAR's retail revenues related to standard offer and default services are fully reconciled to the costs incurred and have no impact on net income. The current quarter's 4.2% increase in retail kWh sales primarily reflects growth in the residential and commercial sectors of 7.2% and 3.7%, respectively. NSTAR Electric's sales to residential and commercial customers were approximately 30% and 59%, respectively, of its total retail sales mix for the current three-month period.

Wholesale electric revenues were $24.4 million in the third quarter of 2001 compared to $21.9 million in the same period of 2000, an increase of $2.5 million, or 11%, due primarily to settlement amounts received from Pilgrim contract customers.

Gas revenues were $41.4 million in the third quarter of 2001 compared to $41.9 million in the same period of 2000, a decrease of $0.5 million, or 1%. The slight decline in revenues is primarily attributable to the 19.5% decrease in firm sales and transportation services primarily due to the economic slowdown in the commercial and industrial sectors and the lower cost of gas supply recoveries. NSTAR Gas' firm sales and transportation services to residential and combined commercial and industrial customers were approximately 35% and 62%, respectively, of total firm sales and transportation services in the current quarter.

Other revenues were $53.8 million in the third quarter of 2001 compared to $43.9 million in the same period of 2000, an increase compared to $43.9 million in the same period of 2000, an increase of $9.9 million, or 23%. This increase primarily reflects NEPOOL-related transmission revenues and revenues realized in conjunction with district energy operations.

Operating expenses

Purchased power costs were $499.4 million in the third quarter of 2001 compared to $309.4 million in the same period of 2000, an increase of $190 million, or 61%. The increase in expense reflects higher purchased power requirements due to a 4.2% increase in electric retail and wholesale sales, the recognition of previously deferred purchased power costs resulting from current year collections of these costs, partially offset by lower wholesale electric costs. NSTAR adjusts its electric rates to collect the costs it actually incurs related to energy supply. Differences between the level of revenues collected and costs actually incurred are recorded as a regulatory asset or liability. Due to the rate adjustment mechanisms, changes in the amount of energy supply expense have no impact on earnings. The cost of gas sold, representing NSTAR Gas' supply expense, was $25.1 million for the third quarter of 2001 compared to $24.5 million in the same period of 2000, an increase of $0.6 million, or 2%, primarily due to the slight increase in firm sales. These expenses are also fully reconciled to the current level of revenues collected and therefore, have no impact on net income.

Operations and maintenance expense was $102.7 million in the third quarter of 2001 compared to $96.5 million in the same period of 2000, an increase of $6.2 million, or 6%. This increase reflects higher electric distribution weather-related maintenance costs during this past summer, higher bad debt expense of $2.5 million and higher pension costs. These factors were partially offset by merger-related savings.

Depreciation and amortization expense was $60.5 million in the third quarter of 2001 compared to $67.9 million in the same period of 2000, a decrease of $7.4 million, or 11%. The decrease reflects the buy-down of the Seabrook investment in November 2000 utilizing a portion of the proceeds from the sale of Canal Electric's generating units and to a lesser extent, the write-down of the remaining assets of a district energy facility, partially offset by a slightly higher level of system-wide depreciable plant in service.

Demand side management (DSM) and renewable energy programs expense was $19.8 million in the third quarter of 2001 compared to $23.3 million in the same period of 2000, a decrease of $3.5 million, or 15%, primarily due to the timing of expenses for these programs. These costs are collected from customers on a fully reconciling basis and therefore, fluctuations in program costs have no impact on earnings. In addition, NSTAR earns incentive amounts in return for increased customer participation.

Property and other taxes were $22.5 million in the third quarter of 2001 compared to $20.1 million in the same period of 2000, an increase in income of $2.4 million, or 12%. The increase was due to the fact that during 2000, Boston Edison was reimbursed for the majority of its payments, in lieu of property taxes, to the Town of Plymouth by Entergy. Entergy purchased the Pilgrim Station in 1999.

Income taxes from operations were $45.8 million in the third quarter of 2001 compared to $41 million in the same period of 2000, an increase of $4.8 million, or 12%, reflecting higher pre-tax operating income.

tax operating income.

Other income (deductions)

Other deductions was $2 million in the third quarter of 2001 compared to deductions of $0.3 million in the same period of 2000, a net change of $1.7 million. The current period primarily reflects $3.8 million for the accrual of costs associated with a district energy facility shutdown, partially offset by an insurance claim settlement of $0.9 million.

Interest charges

Interest on long-term debt and transition property securitization certificates was $39.9 million in the third quarter of 2001 compared to $38.5 million in the same period of 2000, an increase of $1.4 million, or 4%. The increase primarily reflects issuance of $200 million of 8% NSTAR bonds in October 2000, offset by the retirement of several long-term debt issues during the second half of 2000 by Boston Edison. The current period increase is partially offset by a reduction of securitization certificates interest of $0.9 million due to the scheduled partial paydown of this debt. Other interest expense was $5.7 million in the third quarter of 2001 compared to $22.5 million in the same period of 2000, a decrease of $16.8 million, or 75%, primarily due to a reconciliation of certain regulatory deferrals that resulted in additional interest expense recorded in 2000. The benefit of lower interest rates is almost entirely offset by higher average short-term borrowing levels from banks. The increase in borrowing is primarily the result of working capital requirements.

Results of Operations - Nine Months Ended September 30, 2001 vs. Nine Months Ended September 30, 2000

Earnings (loss) per common share were as follows:

	Nine Months Ended September 30,		
	2001	2000	% Change
Basic			
Before one-time RCN charge	$ 2.71	$2.38	13.9
After one-time RCN charge	$(0.57)	$2.38	(123.9)
Diluted			
Before one-time RCN charge	$ 2.70	$2.37	13.9
After one-time RCN charge	$(0.57)	$2.37	(124.1)

Earnings were $143.6 million, or $2.71 and $2.70 per basic and diluted common share, respectively, for the first nine months of 2001 before a one-time, non-cash, after-tax charge of $173.9 million, or $3.28 per basic share, related to NSTAR's total investment in RCN Corporation (RCN). Factors that contributed to the $11.7 million, or 8.9%, improvement in earnings before the one-time charge include an increase in retail kWh sales of 2.2%, an increase in firm gas sales of 2.2%, lower regulatory interest expense due to a reconciliation that resulted in additional interest expense recorded in 2000, a decrease of approximately 2.5 million common shares outstanding and a one-time gain ($4.5 million) associated with the receipt of equity securities issued in conjunction with the demutualization of two mutual insurance companies that provide coverage to NSTAR subsidiaries. These factors were offset by a reduction in mitigation incentives factors were offset by a reduction in mitigation incentives revenues of $9.6 million and the accrual of costs associated with a district energy facility shutdown.

As previously disclosed and further discussed in this report, NSTAR is in the process of converting its joint venture investment in RCN into shares of RCN common stock. NSTAR's investment in RCN includes 4.1 million common shares that it currently holds and 7.5 million common shares that it expects to receive for its remaining interest in the joint venture. Consistent with the performance of the telecommunications sector as a whole, the market value of RCN's common shares has decreased significantly over the past several months. As a result, NSTAR recognized an impairment of its investment in RCN. NSTAR determined that this decline in market value is "other-than-temporary" as defined by SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities." Including the impact of this adjustment, which resulted in a one-time, non-cash, after-tax charge of $173.9 million, NSTAR reported a loss of $30.4 million, or $0.57 per basic and diluted share, for the nine months ended September 30, 2001, compared to earnings of $131.8 million, or $2.38 per basic share and $2.37 per diluted share, for the same period in 2000.

Earnings per common share for the first nine months of 2001 reflect a lower level of common shares outstanding resulting from the repurchase of 5 million shares during 2000 that had a positive impact of approximately twelve cents per share. The results of operations for the nine-months ended September 30, 2001 are not indicative of the results that may be expected for the entire year due to the seasonality of electric and gas sales and revenues. Refer to Note B to the Unaudited Condensed Consolidated Financial Statements.

Operating revenues

Operating revenues increased 25% during the first nine months of 2001 as follows:

(in thousands)	
Retail electric revenues	$ 387,840
Wholesale electric revenues	8,337
Gas revenues	69,023
Other revenues	24,412
Increase in operating revenues	$ 489,612

Retail electric revenues were $1,949.7 million in the first nine months of 2001 compared to $1,561.9 million in the same period of 2000, an increase of $387.8 million, or 25%. The change in retail revenues includes a 2.2% increase in retail kWh sales, higher rates implemented in January and July 2001 for standard offer ($176.6 million) and default services ($214.1 million), increases in net distribution revenues of $5.5 million and transmission revenues of $39.6 million and the absence in the current period of a $31 million fuel charge refund to customers in the same period last year. These revenue increases were partially offset by the recognition in 2000, of earned mitigation incentives related to prior periods. The change in mitigation incentive revenue entitlements amounted to $9.6 million. Theses incentives are allowed for successfully lowering certain transition charges. The increase in NSTAR's retail revenues related to standard offer and default services are fully reconciled to the costs incurred and have no impact on net income. The 2.2% increase in year-to-date retail kWh sales primarily reflects growth in the residential and commercial sectors of 4% and 2.5%, respectively. NSTAR Electric's sales to retail residential and commercial customers were approximately 30% and 58%, respectively, of its total retail sales mix for the current nine-month period.

Wholesale electric revenues were $69.6 million in the first nine months of 2001 compared to $61.3 million in the same period of 2000, an increase of $8.3 million, or 14%. This increase in wholesale revenues primarily reflects increased demand from a public transit authority and municipal contracts.

Gas revenues were $304.8 million in the first nine months of 2001 compared to $235.8 million in the same period of 2000 an increase of $69 million, or 29%. The increase in revenues is primarily attributable to recovery of prior period gas costs, partially offset by a 1.4% decline in firm sales and transportation due to the economic slowdown in the commercial and industrial sectors. Heating degree days were 1.1% above the same period in 2000 and 0.3% higher than normal offsetting the decrease in firm sales and transportation. NSTAR Gas' firm sales to residential and combined commercial and industrial customers were approximately 64% and 32%, respectively, of total firm sales for the current nine-month period.

Other revenues were $163.7 million in the first nine months of 2001 compared to $139.3 million in the same period of 2000, an increase of $24.4 million, or 18%. This increase primarily reflects NEPOOL-related transmission revenues and higher revenues realized in conjunction with district energy operations.

Operating expenses

Purchased power costs were $1,292.7 million in the first nine months of 2001 compared to $879.7 million in the same period of 2000, an increase of $413 million, or 47%. The increase in expense reflects higher purchased power requirements due to a 2.2% increase in retail sales, a 5.5% increase in wholesale sales, partially offset by lower costs that reflect the prices of natural gas and oil. Further contributing to this increase is the recognition of previously deferred standard offer and default service supply cost resulting from the current year collection of these costs. NSTAR adjusts its electric rates to collect the costs related to energy supply from customers on a fully reconciling basis. Due to the rate adjustment mechanisms, changes in the amount of energy supply expense have no impact on earnings. The cost of gas sold, representing NSTAR Gas' supply expense, was $196.9 million for the first nine months of 2001 compared to $128.2 million in the same period of 2000, an increase of $68.7 million, or 54%, due primarily to the recognition of previously deferred cost of gas resulting from current year collection of these costs. These expenses are also fully reconciled to the current level of revenues collected.

Operations and maintenance expense was $306 million in the first nine months of 2001 compared to $305.3 million in the same period of 2000, an increase of $0.7 million, or 0.2%. This slight increase reflects electric distribution weather-related maintenance costs, particularly during this past summer, higher bad debt expense of $4.8 million expense and higher pension costs. These factors were partially offset by merger-related savings.

Depreciation and amortization expense was $174.6 million in the

Depreciation and amortization expense was $174.6 million in the first nine months of 2001 compared to $185.8 million in the same period of 2000, a decrease of $11.2 million, or 6%. The decrease reflects the buy-down of the Seabrook investment in November 2000 utilizing a portion of the proceeds from the sale of Canal Electric's generating units and to a lesser extent, the write-down of the remaining assets of a district energy facility, partially offset by a slightly higher level of system-wide depreciable plant in service.

Demand side management (DSM) and renewable energy programs expense was $58.2 million in the first nine months of 2001 compared to $59 million in the same period of 2000, a decrease of $0.8 million, or 1% primarily due to timing of DSM expense. These costs are collected from customers on a fully reconciling basis and therefore, fluctuations in program costs have no impact on earnings. In addition, NSTAR earns incentive amounts in return for increased customer participation.

Property and other taxes were $72.1 million in the first nine months of 2001 compared to $66.9 million in the same period of 2000, an increase of $5.2 million, or 8%. The increase was due to the fact that during 2000, Boston Edison was reimbursed for the majority of its payments, in lieu of property taxes, to the Town of Plymouth by Entergy. Entergy purchased the Pilgrim Station in 1999.

Income taxes from operations were $101.5 million in the first nine months of 2001 compared to $90.1 million in the same period of 2000, an increase of $11.4 million, or 13%, reflecting higher pre-tax operating income.

Other income (deductions)

Other deductions were $172.9 million in the first nine months of 2001 compared to income of $5.6 million in the same period of 2000, a net decrease in income of $178.5 million directly attributable to the aforementioned one-time, non-cash, after-tax charge related to the carrying value of the RCN investment that is discussed more fully below.

In addition, the current year includes $4.5 million of income associated with the receipt of common stock in connection with the demutualization of two insurance companies. This factor was offset by $3.8 million for the accrual of costs associated with a district energy facility shutdown and an insurance claim settlement of $0.9 million. In 2000, Other income included $2 million in settlement for a prior period billing matter, the impact of the RCN joint-venture losses of approximately $5.6 million, and the recognition of $4.5 million of interest income from a former wholesale contract customer associated with the Pilgrim contract buyout.

Interest charges

Interest on long-term debt and transition property securitization certificates was $120.3 million in the first nine months of 2001 compared to $114.4 million in the same period of 2000, an increase of $5.9 million, or 5%. The increase reflects the issuance of $300 million and $200 million of 8% NSTAR bonds in February and October of 2000, respectively, offset somewhat by the retirement of $199 million in Boston Edison debt throughout 2000. The current period reflects a reduction of securitization certificates interest of $3.1 million due to the partial retirement of this debt. Other interest expense decreased $19.1 million, or 47%, primarily due to a reconciliation of certain million, or 47%, primarily due to a reconciliation of certain regulatory deferrals in conjunction with a MDTE reconciliation that resulted in a partial reversal of prior period expense, lower interest rates, offset by higher short-term borrowing levels from banks. The increase in borrowing is primarily the result of working capital requirements.

RCN Joint Venture and Investment Conversion

NSTAR Com is a participant in a telecommunications venture with RCN Telecom Services, Inc. of Massachusetts, a subsidiary of RCN Corporation (RCN). NSTAR Com has accounted for its equity investment in the joint venture using the equity method of accounting. As part of the Joint Venture Agreement, NSTAR Com has the option to exchange portions of its joint venture interest for common shares of RCN at specified periods. To date, NSTAR Com has received approximately 4.1 million shares of RCN common shares from prior exchanges of its joint venture interest.

On April 6, 2000, NSTAR Com issued its third and final notice to exchange substantially all of its remaining interest in the joint venture into common shares of RCN. Effective with the third notice, NSTAR Com's profit and loss sharing ratio was reduced to zero. Therefore, NSTAR Com no longer recognized any results of operations of the joint venture. During the period January 1, 2000 through April 6, 2000, NSTAR Com recognized $5.6 million in equity losses from the joint venture and has not recorded any further joint venture losses since that date.

On October 18, 2000, NSTAR Com and RCN signed an agreement in principle to amend the Joint Venture Agreement. Among other items, this proposal settled the number of shares to be received for the third conversion of NSTAR Com's remaining equity investment at 7.5 million shares. Management anticipates having a final amended Joint Venture Agreement in place by the end of 2001.

As previously disclosed, management continues to evaluate the carrying value of its entire investment in RCN. Consistent with the performance of the telecommunications sector as a whole, the market value of RCN's common shares has decreased significantly over the past several quarters. Management has determined that this decline in market value is "other-then-temporary" in accordance with the SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities."

In addition, during the first quarter of 2001, the status of the amendment to the Joint Venture Agreement with RCN regarding the 7.5 million shares, led management to determine that its investment in the joint venture was also impaired based on future market expectations for RCN common shares related to this investment.

Therefore, NSTAR Com, recognized an impairment of its entire investment in RCN in the first quarter of 2001. This write-down resulted in an one-time, non-cash, after-tax charge of $173.9 million that is reported on the accompanying Condensed Consolidated Statements of Income as "Write-down of RCN Investment, net."

The RCN shares received, as well as the remaining interest in the joint venture related to the pending 7.5 million shares, are included in Other investments on the accompanying Condensed Consolidated Balance Sheets at their estimated fair value of approximately $41.2 million at September 30, 2001. The fair value of the shares currently held may increase or decrease, at value of the shares currently held may increase or decrease, at any time, as a result of changes in the market value of RCN common shares. The unrealized gain or loss associated with shares currently held will fluctuate due to the changes in fair value of these shares during each period and is reflected, net of associated income taxes, as a component of Other comprehensive income, net on the accompanying Condensed Consolidated Statements of Comprehensive Income (Loss). The cumulative increase or decrease in fair value of these shares as of September 30, 2001 reflect the change since the write-down of these shares as a component of Accumulated other comprehensive income (loss) on the accompanying Condensed Consolidated Balance Sheets. Management will continue to evaluate the carrying value of its investment in RCN.

At September 30, 2001 and December 31, 2000, NSTAR Com had $5.1 million and $47.9 million, respectively, in accounts receivable due from the joint venture. This is primarily the result of construction performed on behalf of the joint venture.

Other Investments

In the second quarter of 2001, NSTAR completed its determination of the accounting for equity securities it previously received in connection with the demutualization of John Hancock Mutual Life Insurance Company and Metropolitan Life Insurance Company. NSTAR and its subsidiaries, as policyholders, received an appropriate distribution of common stock of each company. As a result, NSTAR recognized $4.5 million of other income on these transactions.

These securities are currently available for sale and are included in Other investments on the accompanying Condensed Consolidated Balance Sheets. The value of these common shares was adjusted to reflect market values as of September 30, 2001. The unrealized gain or loss associated with these shares will fluctuate due to changes in current market values and is reflected net of applicable income taxes and is included as a component of Comprehensive income (loss) on the accompanying Condensed Consolidated Statements of Comprehensive Income (Loss). The cumulative increase or decrease in fair value of these shares as of September 30, 2001 is reflected as a component of Accumulated other comprehensive income (loss) on the accompanying Condensed Consolidated Balance Sheets.

Liquidity

NSTAR and its subsidiaries supplement internally generated funds as needed, primarily through the issuance of short-term commercial paper and bank borrowings.

In February and October 2000, NSTAR issued $300 million and $200 million, respectively, 8% notes, due February 2010, of long-term debt related to a $500 million shelf registration. Proceeds from these issues were used to reduce short-term borrowings. These increases in long-term debt were partially offset in 2000 by $199 million in long-term debt retirements, consisting of Boston Edison debenture redemptions of $65 million (6.8% Series) in February, $34 million (9.875% Series) in June and $100 million (6.05% Series) in August.

NSTAR has a $450 million revolving credit agreement with a group of banks effective through November 2002. At September 30, 2001 and December 31, 2000, there were no amounts outstanding under this revolving credit agreement. Also, NSTAR has a $450 million commercial paper program. At September 30, 2001 and December 31, 2000, NSTAR had $349 million and $252 million outstanding, respectively, under its commercial paper program.

On June 15, 2001, Boston Edison notified the holders of its 9 3/8% Series Debentures, due August 15, 2021, that the entire principal amount of these notes (approximately $24.3 million) would be called for redemption on August 15, 2001. The retirement of this series was funded with internally-generated funds.

Boston Edison has approval from the FERC to issue up to $350 million of short-term debt. Boston Edison has a $200 million revolving credit agreement with a group of banks effective through December 2001. As of September 30, 2001 and December 31, 2000, there were no amounts outstanding under this revolving credit agreement. In addition, Boston Edison also has a $100 million line of credit. Both of these arrangements serve as back-up to Boston Edison's $300 million commercial paper program that, as of September 30, 2001 and December 31, 2000, had outstanding $160.5 million and $97 million, respectively. Separately, Boston Edison, effective July 20, 2001, has an additional $50 million line of credit.

Boston Edison has approval from the MDTE to issue from time to time up to $500 million of debt securities through 2002. Proceeds from such issuances covered under this approved financing will be used for repayment or refinancing of certain outstanding equity securities, long-term indebtedness, and for other corporate purposes. On February 20, 2001, Boston Edison filed a registration statement on Form S-3 with the Securities and Exchange Commission (SEC), using a shelf registration process, to issue up to $500 million in debt securities. The SEC declared the registration statement effective on February 28, 2001. When issued, Boston Edison will use the proceeds to pay at maturity long-term debt and equity securities, refinance short-term debt and for other corporate purposes.

In addition, ComElectric, Cambridge Electric and NSTAR Gas, collectively, have $195 million available under several lines of credit. Approximately $134.6 million and $120 million was outstanding under these lines of credit as of September 30, 2001 and December 31, 2000, respectively.

NSTAR's goal is to maintain a capital structure that preserves an appropriate balance between debt and equity. Management believes its liquidity and capital resources are sufficient to meet its current and projected requirements.

New Accounting Standards

In July 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standard (SFAS) No. 142, "Goodwill and Other Intangible Assets" (SFAS 142). This Statement, which is effective for fiscal years beginning after December 15, 2001, establishes accounting and reporting standards for acquired goodwill and other indefinite lived intangible assets. It prohibits entities from continuing amortization of these assets. Instead, goodwill and other intangible assets will be subject to review for impairment. Management is currently assessing the impact of SFAS 142 in light of its regulatory and accounting requirements. Therefore, NSTAR is unable to reasonably estimate the impact of the adoption of this Statement.

On July 5, 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS 143). This Statement, which is effective for fiscal years beginning after June 15, 2002, is effective for fiscal years beginning after June 15, 2002, establishes accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. It applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and (or) the normal operation of a long-lived asset, except for certain obligations of lessees. This standard requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. Management is also currently assessing the impact of SFAS 143 in light of its regulatory and accounting requirements. Therefore, NSTAR is unable to reasonably estimate the impact of the adoption of this Statement.

As of January 1, 2001, NSTAR adopted the FASB SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133), as amended by Statements of Financial Accounting Standards No. 137 and 138, and collectively referred to as SFAS 133. SFAS 133 established accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in contracts possibly including fixed-price fuel supply and power contracts) be recorded on the Consolidated Balance Sheets as either an asset or liability measured at its fair value.

The management of NSTAR has assessed the impact of the adoption of SFAS 133. As part of this assessment, NSTAR formed an implementation team in 2000 consisting of key individuals from various operational and financial areas of the organization. The primary role of this team was to inventory and determine the impact of potential contractual arrangements for SFAS 133 application. The implementation team has performed extensive reviews of critical operating areas of NSTAR and has documented its procedures in applying the requirements of SFAS 133 to NSTAR's contractual arrangements in effect on January 1, 2001. Based on NSTAR's assessment to date, the adoption of SFAS 133 has not had a material adverse effect on its results of operations, cash flows, or financial position.

Safe harbor cautionary statement

NSTAR occasionally makes forward-looking statements such as forecasts and projections of expected future performance or statements of its plans and objectives. These forward-looking statements may be contained in filings with the SEC, press releases and oral statements. Actual results could potentially differ materially from these statements. Therefore, no assurances can be given that the outcomes stated in such forward-looking statements and estimates will be achieved.

The preceding sections include certain forward-looking statements about operating results, environmental and legal issues.

The impacts of continued cost control procedures on operating results could differ from current expectations. The effects of changes in economic conditions, tax rates, interest rates, technology and the prices and availability of operating supplies could materially affect the projected operating results.

could materially affect the projected operating results.

The impacts of various environmental, legal issues, and regulatory matters could differ from current expectations. New regulations or changes to existing regulations could impose additional operating requirements or liabilities other than expected. The effects of changes in specific hazardous waste site conditions and cleanup technology could affect estimated cleanup liabilities. The impacts of changes in available information and circumstances regarding legal issues could affect estimated litigation costs.

Part II - Other Information

Item 3. Quantitative and Qualitative Disclosures about Market Risk

There have been no material changes since year-end.

Item 4. Submission of Matters to a Vote of Security Holders.

None

Item 5. Other Information

None

Item 6. Exhibits and Reports on Form 8-K

a) Exhibits filed herewith and incorporated by reference:

Exhibit 4 - Instruments defining the rights of security holders, including indentures

Management agrees to furnish to the Securities and Exchange Commission, upon request, a copy of any agreements or instruments defining the rights of holders of any long-term debt whose authorization does not exceed 10% of total assets.

Exhibit 15 - Letter re unaudited interim financial information

15.1 - Report of Independent Accountants

Exhibit 99 - Additional exhibits

99.1 - Letter of Independent Accountants

Form S-4 Registration Statement filed by NSTAR on May 12, 1999 (Filed No. 333-78285); Post-effective Amendment to Form S-4 on form S-3 filed by NSTAR on August 19, 1999 (File No. 333-78285); Post-effective Amendment to form S-4 on Form S-8 filed by NSTAR on August 19, 1999 (Filed No. 333-78285); Form S-8 Registration Statement filed by NSTAR on August 19, 1999 (File No. 333-85559).

b) No Form 8-K was filed during the third quarter of 2001.

Signature

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

NSTAR
(Registrant)

Date: November 14, 2001

/s/ ROBERT J. WEAFER, JR.
Robert J. Weafer, Jr.
Vice President, Controller
and Chief Accounting Officer

Record Request AG-10

Provide the Company's analysis of the effects of the various bid options on other Sponsors.

Response

Please see Attachments RR-AG-10(a) and RR-AG-10(b) * **CONFIDENTIAL** * for the requested analysis.

Attachment (a) uses the same information as contained in Attachment AG-1-11(g) * **CONFIDENTIAL** *, which uses the DPS price, except that the entitlement percentage is 55 percent (the total entitlement share of the Vermont Sponsors) and a PPA is included in all four offers. The results show that Offer 1 provides the maximum savings, while Offer 4 offers the least savings.

Attachment (b) uses the same information as contained in Attachment AG-1-11(h) * **CONFIDENTIAL** *, which uses the Henwood price, except that the entitlement percentage is 55 percent and a PPA is included in all four offers. The results of this sensitivity analysis also show that Offer 1 provides the maximum savings, while Offer 4 offers the least savings.

The relative savings are the same between the two scenarios because the market price is also used to determine the value of the Continued Operation option. This relationship would be true no matter what market price were used.

Attachments RR-AG-10(a) and RR-AG-10(b) contain confidential, sensitive and proprietary information, which is the subject of a motion for protected treatment pursuant to G.L. c. 25, § 5D. The PROTECTED MATERIALS will be made available in this proceeding subject to the execution of an appropriate non-disclosure agreement.